Final Report

Hoechst Celanese Chemical Group, Ltd.
Bay City, Texas
Closure Report
Injection Well WDW-32 (Well No. 3)

ECO Job 96015

ECO Solutions, Inc.
9800 Richmond Avenue
Suite 320
Houston, Texas 77042
(713) 780-1955
FAX (713) 780-0870

HOECHST CELANESE CHEMICAL GROUP, LTD.
BAY CITY TEXAS PLANT

CLOSURE OF CLASS I INJECTION WELL
WDW-32 (WELL #3)

SOLUTIONS, INC.

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PLUG AND ABANDON CERTIFICATION

The undersigned has reviewed all pertinent information concerning the plugging and abandonment of the Hoechst Celanese Chemical Group, Ltd. (HCCG) Class I injection well WDW-32 (Well #3) with regards to the plans and specifications set forth in Texas Natural Resource Conservation Commission (TNRCC), Underground Injection Control (UIC) Program and the current Federal and TNRCC requirements for the plugging and abandonment of a Class I injection well located in the State of Texas.

In accordance with TNRCC/UIC Program, 31 TAC 331.46 and the closure standards of HCCG's UIC Permit, I certify that WDW-32 (Well #3) was plugged and abandoned in compliance with the permit and applicable TNRCC regulations in effect at the time of closure

This certification is not valid unless the engineer's original signature and raised seal are present.

11/15/96
DATE

(SEAL)

Wesley W. Smith
Wesley W. Smith, P.E.
Texas Professional Engineer
No. 29398

1.0 INTRODUCTION AND SUMMARY

1.1 INTRODUCTION

Hoechst Celanese Chemical Group, Ltd. (HCCG) contracted with ECO Solutions, Inc. (ECO) to perform the plugging and abandonment (P&A) of their Class I injection well, WDW-32 (Well No. 3), located at their Bay City plant. A schematic drawing of WDW-32 prior to and following P&A operations are included as Figure 1 and Figure 2, respectively. The attached report details the field activities and data associated with project.

The following provides an overview of the key elements of the P&A on WDW-32 (Well No. 3).

- Hoechst Celanese submitted and received approval for a closure plan as required by the Texas Natural Resource Conservation Commission (TNRCC), Underground Injection Control (UIC) Program, and the regulations contained within 31 TAC 331.46.

- A 50' section of the 9-5/8" long string casing string above the injection interval was removed by milling and underreamed out to a 15" radial diameter. Subsequent cementing operations re-established a secure cement plug between the 9 5/8" casing confining shales.

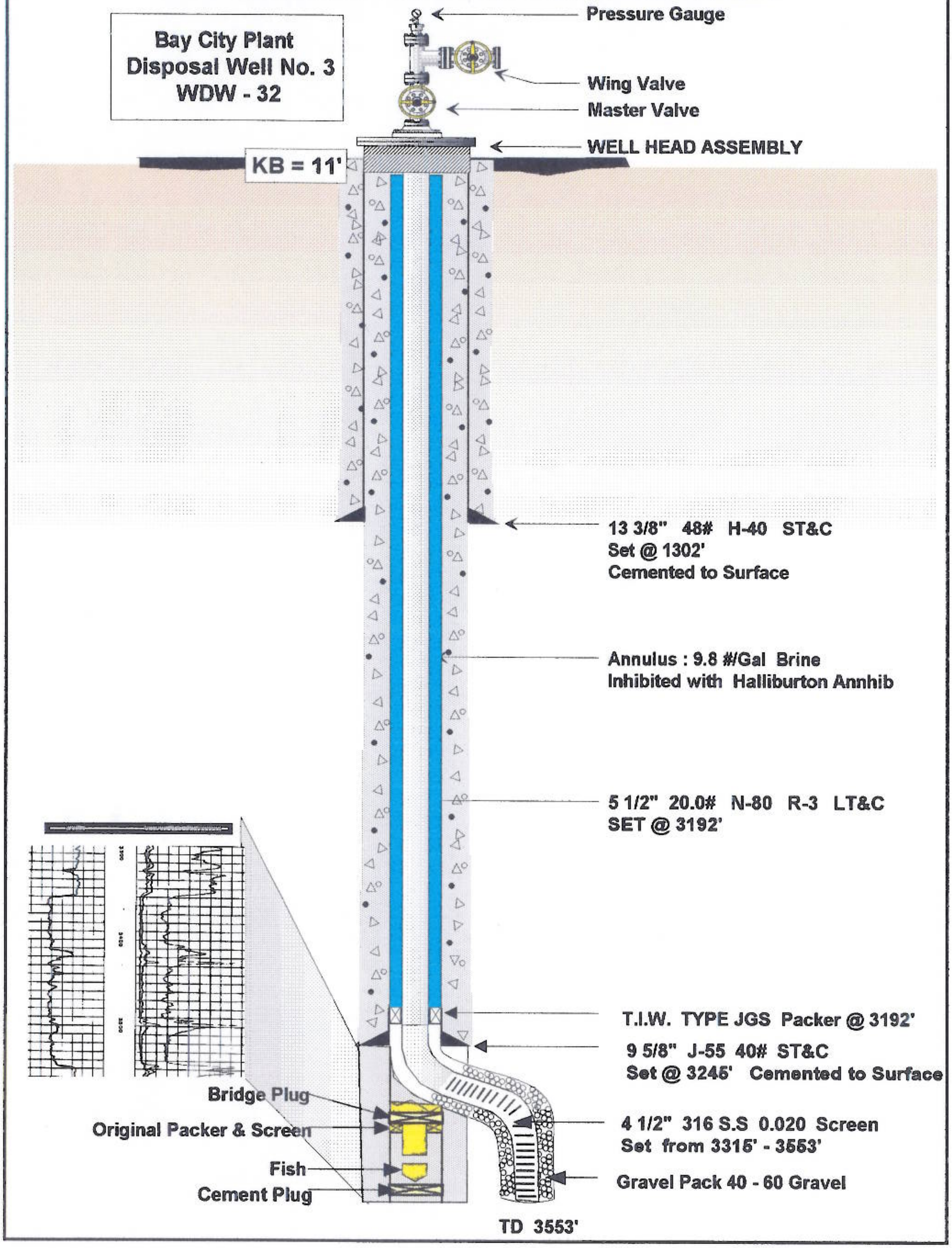
- Squeeze cementing was accomplished through a perforated section of 9+5/8" casing below 13+3/8" surface casing shoe depth. This action improved the cement seal below the lowermost underground source of drinking water (USDW).

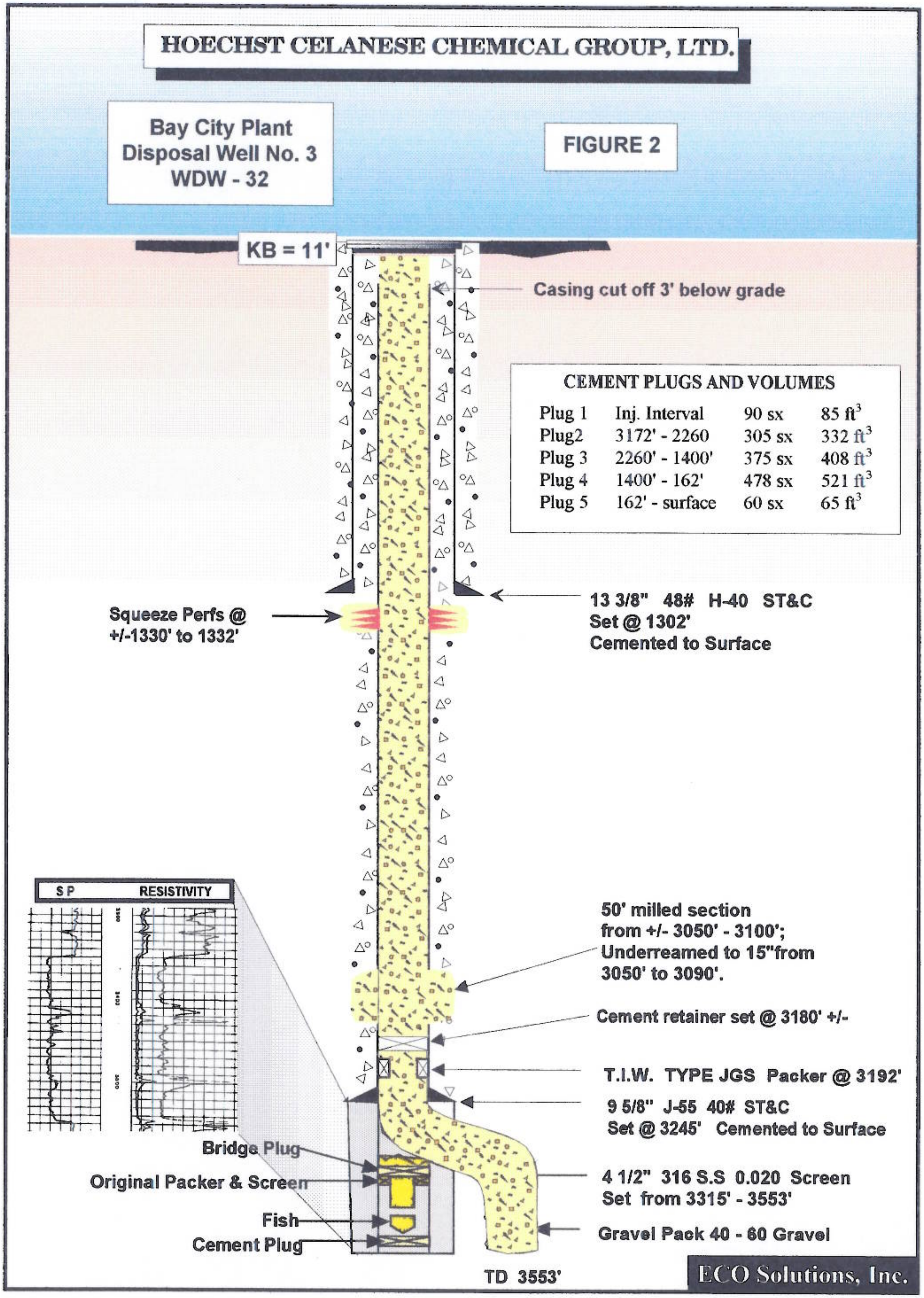
- Pertinent P & A data was placed on welded steel plate installed at the surface.

- Contained within the closure report is an executed copy of the Consent To Revocation Of Texas Natural Resource Conservation Commission Permit WDW- 32 form and a copy of the recorded deed was submitted to the TNRCC under a separate cover.

HCCG and/or ECO personnel contacted the TNRCC Austin office prior to commencing and during field operations to allow TNRCC personnel to witness cementing events during the P&A field operations.

FIGURE 1
HOECHST CELANESE CHEMICAL GROUP, LTD.





CEMENT PLUGS AND VOLUMES

Plug 1	Inj. Interval	90 sx	85 ft^3
Plug2	3172' - 2260	305 sx	332 ft^3
Plug 3	2260' - 1400'	375 sx	408 ft^3
Plug 4	1400' - 162'	478 sx	521 ft^3
Plug 5	162' - surface	60 sx	65 ft^3

1.2 SUMMARY OF CLOSURE ACTIVITIES

Dawson workover rig no. 356 was rigged up on WDW-32 (Well #3) to perform the milling and underreaming operations on the 9+5/8" 0. D. casing string. A Halliburton wireline set "EZ-SV" cement retainer was set at 3180' ± . Cement plug No. 1 consisting of 90 sacks (85 ft^3) of Halliburton premium cement was placed into the injection interval and 10' above the cement retainer. The 9+5/8" casing was milled from 3050' to 3100' in the confinement interval and then the cement and formation was underreamed from 3050' to 3090' to a radial diameter of 15". Cement plug No 2 consisting of 305 sacks (332 ft^3) of Halliburton premium cement was placed from 3172' to 2260'. Cement plug No. 3 consisting of 375 sacks (408 ft^3) of Halliburton premium cement was placed from 2260' to 1400'. The 9+5/8" O.D. long string casing was perforated from 1330' to 1332' with 4 shots per foot. Cement No. 4 consisting of 478 sacks(521 ft^3) of Halliburton premium cement was placed from 1400 to 162'. A final cement plug no. 5 consisting of 60 sacks (65 ft^3) was placed from 162' to the surface. A 1/2" thick stainless steel plate with pertinent data inscribed on top, was welded to 9+5/8" casing extending up to grade and surrounded by cement at the surface.

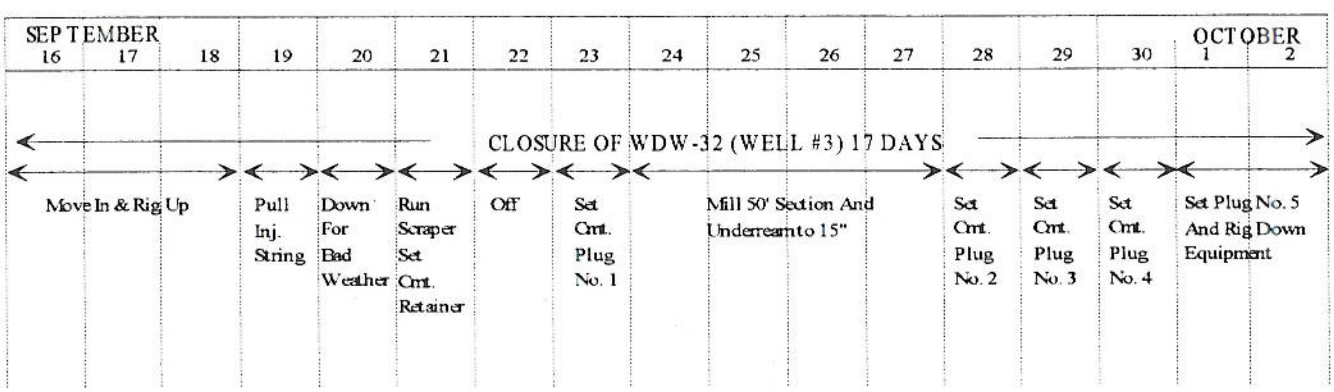
The plugging and abandonment of HCCG's WDW-32 field work was completed on October 2, 1996.

1.3 PROJECT TIMELINE

Figure 3 below is a project timeline that illustrates the key closure events versus the date. The field activities started on September 16, 1996 and ended on October 2, 1996. The total number of field days was 17.

Figure 3

CLOSURE OF WDW-32 (WELL #3) TIMELINE



2.0 SUMMARY OF FIELD ACTIVITIES

MONDAY 9/16/96

Start of field operations. Move in and rig up equipment for well closure. Conduct safety orientations for the service company personnel. The equipment included the open top mud tank and PZ-7 pump. After spotting the pump and tanks, the rig tank was filled with 200 bbls of brine. The Dawson rig arrived on location for move in tomorrow.

A meeting between ECO site personnel and Merrick Saucier, Bryan Barrington and Ray Horton with Hoechst Celanese was rescheduled to Tuesday.

TUESDAY 9/17/96

Continue to move in and rig up equipment for well closure. The equipment included the drilling rig, substructure, blow out preventors, rig pumps and other rental tools. Rig up Dawson rig and pump 200 bbls of brine into well to flush well and eliminate any back pressure. Remove existing Larkin well head and pick up on 5 1/2" tubing. The packer seal assembly was freed from the packer with no problems.

A meeting was held between ECO on site personnel and Merrick Saucier, Bryan Barrington and Ray Horton with Hoechst Celanese. The purpose of the meeting was to discuss project cost and ways to improve cost control out of scope changes and possible contingencies.

WEDNESDAY 9/18/96

Nipple up blow out preventors and Hydril stack. Install substructure to workover rig utilizing HCCG's Grove crane and cherry picker. Rig up and adjust rig control equipment to substructure. Set up pipe racks. Franks Casing Crew arrived on location and rigged up their tongs and lay down machine in preparation for removal of the injection string from WDW-32 (Well #3). Pull of the hole and lay down 5 ½ " injection string. The external condition of injection string was visually observed to be in excellent condition. Used Hoechst Celanese cherry pickers and riggers to move injection string to wash racks and move work string to well site. After the substructure was installed, measurements could then be taken for the flow line. A meeting was held with Halliburton to confirm the cementing specifications for the first cement plug.

THURSDAY 9/20/96

Finish reconfiguring rig controls to accommodate substructure. Complete modifications to bell nipple and install same on top of Hydril. Complete connections to mud circulating system. Finish picking up 3 1/2" drill pipe. Make up casing scraper and bottom hole assembly equipment. Go into the hole with several joints before shutting down for the night.

FRIDAY 9/20/96

A meeting was held with ECO and Hoechst Celanese project personnel and a decision was made to halt the field operations for this day due to severe weather. Thomas Jones contacted Mr. Jim Boswell with the TNRCC to update him on the delay. Mr. Boswell informed ECO that the TNRCC does not intend to be on location for the setting of the first cement plug. He would like to verify the setting of the next cement plug across the interval which has been milled and underreamed.

SATURDAY 9/21/96

Finish going into the hole with 3 1/2" drill pipe and scraper. Pull scraper from the well and remove from bottom hole assembly. Rig up wireline unit and make a run with the gauge ring and junk basket. Make up cement retainer and run into the hole using the wireline unit. Set the cement retainer approximately 10' above the packer was left in the hole.

SUNDAY 9/22/96

A decision was made by ECO, and approved by Hoechst Celanese to shut down the field activities for this day. The shut down was accomplished without incurring daily cost and allowed ECO to improve coordination for the upcoming section milling operations and the change to 24 hour per day operations.

MONDAY 9/23/96

Unload drilling mud from transports into tanks. Go into the hole with the 3 1/2" drill pipe with seal assembly to top of retainer. Displace brine in well with mud. Sting into the cement retainer and confirm that it is open to the injection interval. Pump brine pre-flush ahead of the cement. Cement the injection interval using 90 sx of Halliburton premium cement (plug no. 1). Maximum pressure during cementing is 500 psig. The drill string was picked up 60' and reversed out the brine with mud. The retainer was closed and approximately 10' of cement was left on top. Pull out of the hole with the 3 1/2" drill pipe. The TNRCC was notified prior to the cementing and they informed ECO that a representative would not be on location to verify the pumping of the first plug.

TUESDAY 9/24/96

Start 24 hour operations. Wes Smith arrive on location to work the night shift. Wait on cement. Unload drill collars, section milling and underreaming equipment. Rig up power swivel. Rig up power tongs. Pick up drill collars and section milling bottom hole assembly. The drilling mud that arrived on location did not have proper viscosity and water loss properties. The viscosity of the mud was too low to provide sufficient cleaning capacity of the well bore during milling operations. *Note: A viscous mud is required to clean the hole of metal cuttings.* Elevating the mud viscosity was needed since the mud arrived at the location with the lower viscosity and high water loss condition. Approximately eight (8) hours of circulating time was needed to raise the mud viscosity and lower the water loss to the required levels. Go in hole with section mill, drill collars and drill pipe.

WEDNESDAY 9-25-96

Prepare to start milling 9-5/8" casing from 3050' to 3100'. Rig up power and swivel and break circulation. Unable to circulate through shale shaker. Changed out screen (60 mesh in place of 40 mesh) - circulation OK. Milling 3050' - 3059 ' with 2,000 - 5,000 lb. on mill and 100 RPM. *Note: The workover rig is secured to a beam and not tied down with anchors due to location restrictions.* Due to heavy bit weight and torque due to milling, rig is moving considerably. Lessen weight and milling continued slowly with no problems. Plan to set deadmen stakes to physically stabilize rig. Recommended to HCCG and they concurred to allow Dawson to install rig anchors. Replaced centrifugal pump drive belts on P2-7 pump. Milling 3059' to 3061' in 2 hours. Shut down due to damaged valve/seat assembly in large triplex pump (PZ-7). Attempted to pull section mill inside casing. Pull 50,000 lb. above string weight and unable to collapse cutters on mill. Made decision to 1) leave section mill in sectioned open hole and 2) put no. 2 pump no. 2 on hole to circulate drilling fluid around section mill while waiting on pump parts. Shut down waiting on new pump parts.

THURSDAY 9/26/96

Install pump parts. Milling 3061' to 3070' (4-1/2 hr.) using 5,000 lb. weight on mill and 85 RPM with 6 barrels per minute pump rate. Good metal cutting recovery. Mud: 10.3 pounds per gallon with a viscosity of 65 sec/qt. Milling operations continued from 3070' to 3100'.

FRIDAY 9/27/96

Finish removing section mill and bottom hole assembly from well. Remove mill and make up underreamer . Mill has been damaged due to efforts to close blades so that it could be removed. Go into the hole and start underreaming section from 3050' to 3100'. The underreaming will remove old cement from the well bore out to a diameter of 15". At approximately 3090' underreamer became stuck in the hole. *Note: The most likely cause is the presence of casing centralizers and/or wire scratchers placed on the casing during original installation.* The underreamer was freed after pulling 200,000 lb. above string weight. A decision was made not to underream the last 10' (3090' - 3100') due to the risk of becoming stuck again. Tom Jones contacted Bryan Barrington and he agreed with this decision. Start out of the hole with the underreamer.

SATURDAY 9/28/96

Continue out of the hole with the underreamer. Kathryn Herzog with the TNRCC arrived on location to witness the upcoming cementing operations. Rig up Halliburton. Start in the hole with open ended drill pipe. Spot a balanced plug no. 2 using 305 sx (332 ft^3) premium cement across the milled interval up to a depth of 2260'. Pull out of the hole with the drill pipe and wait on cement.

End of 24 hour operations. Wes Smith returned to Houston.

SUNDAY 9/29/96

Go into the hole open ended and tag the top of the cement plug at 2260'. Rig up Halliburton and cement interval from 2260' to 1400' (plug no. 3). Volume of cement was 375 sk (408 ft^3) of premium neat. Pull drill string up hole to 1480' and reverse out. Pull out of hole and wait on cement. Rig down tongs, lay down drill collars. Wait on cement.

MONDAY 9/30/96

Go in hole with 8 3/4" bit and tag top of cement at 1380'. Reverse circulate mud out of hole and replace with brine. Pull out of the hole laying down drill pipe. Rig up Western Atlas and go into hole with 5" perforating gun. Perforate from 1330' - 1332' with 4 shots per foot. Pull out of the hole with the perforating gun. Rig up Halliburton and go into hole open ended. Cement 9 5/8" casing with 478 sacks (521 ft^3) of premium cement (plug no. 4). It appears that the perforations are taking and unknown quantity of cement. A decision was made to tag the top of cement in the morning and cement as required.

TUESDAY 10/1/96

Go in hole and tag top of cement at 162'. Pull out of the hole. Rig down substructure and pipe racks. Nipple down blow out preventers and Hydril. Go in hole open ended with drill pipe to 162'. Rig up Halliburton. Pick up on blow out preventers and hydril stack to prevent cement from entering this equipment. Fill remaining 9 5/8" casing with 65 ft^3 (60 sx) cement (plug no. 5). Rig down and release Halliburton. Start rigging down Dawson workover rig for move to WDW-49 (well #4). Remove anchors and reinstall at the WDW-49 (well #5) location. Begin moving other equipment to WDW-49 (well #4). Thomas Jones contacted Jim Boswell and Kathryn Herzog with the TNRCC to notify them about the end of operations on WDW-32 (well #3) and the anticipated schedule for WDW-49 (well #4).

WEDNESDAY 10/2/96

Rig down substructure and move to WDW-49 (well #4) location. Rig down and move rig to other well location. Continue to rig down and clean up area around WDW-32 (well #3).

APPENDIX A

CONSENT TO REVOCATION OF TEXAS NATURAL RESOURCE CONSERVATION COMMISSION PERMIT

SOLUTIONS, INC.

CONSENT TO REVOCATION OF

TEXAS NATURAL RESOURCE CONSERVATION COMMISSION PERMIT

I, C.R. Pennington, Facility Manager, acting on behalf of
(Name & Title)
Hoechst Celanese Chemical Group, Ltd., do hereby consent to
(Name of Permittee)

the revocation of Texas Natural Resource Conservation Commission Permit No. WDW-32, pursuant to the provisions of 30 TAC Section 305.67 (b).

The activities regulated by the permit were:

( ) Never begun (Wastewater treatment facility was not constructed)

(X) Terminated on or about (Date) October 2, 1996 (Waste Disposal Well plugged and abandoned)

Facility dismantled ( ); Facility will be dismantled ( ); Facility will be sold and relocated ( ).

( ) Diverted to another permitted wastewater treatment system
Please identify the facility to which flow has been diverted
__________ and the approximate
date the diversion occurred __________.

I also certify that there are no materials remaining at the permitted site which endanger ground or surface water quality.

(Signature)

(409) 241-4000
(Telephone No.)

November 13, 1996
(Date)

APPENDIX B

CEMENTING INFORMATION

Plugging Record

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

FORM W-3
Rev. 10/78

API NO. (if available)

1. RRC District

FILE IN DUPLICATE WITH DISTRICT OFFICE OF DISTRICT IN WHICH WELL IS LOCATED WITHIN THIRTY DAYS AFTER PLUGGING

4. RRC Lease or ID Number

2. FIELD NAME (as per RRC Records): Bay City

3. Lease Name: Celanese WDW-32

5. Well Number: 3

6. OPERATOR: ECO Solutions

6a. Original Form W-1 Filed in Name of:

10. County: Matagorda

7. ADDRESS

6b. Any Subsequent W-1's Filed in Name of:

11. Date Drilling Permit Issued

8. Location of Well, Relative to Nearest Lease Boundaries of Lease on which this Well is Located: Feet From Line and Feet From Line of the Lease

12. Permit Number

9a. SECTION, BLOCK, AND SURVEY

9b. Distance and Direction From Nearest Town in this County

13. Date Drilling Commenced

16. Type Well (Oil, Gas, Dry)

Total Depth

17. If Multiple Completion List All Field Names and Oil Lease or Gas ID No.'s

GAS ID or OIL LEASE #	Oil-O Gas-G	WELL #

14. Date Drilling Completed

18. If Gas, Amt. of Cond. on Hand at time of Plugging

15. Date Well Plugged

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7	PLUG #8
*19. Cementing Date	9/28/96							
20. Size of Hole or Pipe in which Plug Placed (inches)								
21. Depth to Bottom of Tubing or Drill Pipe (ft.)								
*22. Sacks of Cement Used (each plug)	305							
*23. Slurry Volume Pumped (cu. ft.)	332							
*24. Calculated Top of Plug (ft.)	2453							
25. Measured Top of Plug (if tagged) (ft.)								
*26. Slurry Wt. #/Gal.	16.2							
*27. Type Cement	Prem/Neat							

28. CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT. #/FT.	PUT IN WELL (ft.)	LEFT IN WELL (ft.)	HOLE SIZE (in.)

29. Was any Non-Drillable Material (Other than Casing) Left in This Well ☐ Yes ☐ No

29a. If answer to above is "Yes" state depth to top of "junk" left in hole and briefly describe non-drillable material. (Use Reverse Side of Form if more space is needed.)

30. LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS

FROM	TO	FROM	TO
FROM	TO	FROM	TO
FROM	TO	FROM	TO
FROM	TO	FROM	TO
FROM	TO	FROM	TO
FROM	TO	FROM	TO

I have knowledge that the cementing operations, as reflected by the information found on this form, were performed as indicated by such information.
* Designates items to be completed by Cementing Company. Items not so designated shall be completed by Operator.

Signature of Cementer or Authorized Representative

HALLIBURTON ENERGY SVCS.
Name of Cementing Company

CERTIFICATE:
I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct, and complete, to the best of my knowledge.

Michael Supak — REPRESENTATIVE OF COMPANY
Service Supervisor — TITLE
9/28/96 — DATE
Phone 800 (A/C) 223-0898 (NUMBER)

SIGNATURE: REPRESENTATIVE OF RAILROAD COMMISSION

Cementer: Fill in shaded areas. Operator: Fill in other items.

Form W-15
Cementing Report
Rev. 4/1/83
483-045

RAILROAD COMMISSION OF TEXAS
Oil and Gas Division

1. Operator's Name (As shown on Form P-5, Organization Report)	2. RRC Operator No.	3. RRC District No.	4. County of Well Site

5. Field Name (Wildcat or exactly as shown on RRC records)	6. API No. 42-	7. Drilling Permit No.

8. Lease Name	9. Rule 37 Case No.	10. Oil Lease/Gas ID No.	11. Well No.

CASING CEMENTING DATA:			SURFACE CASING	INTER-MEDIATE CASING	PRODUCTION CASING		MULTI-STAGE CEMENTING PROCESS	
					Single String	Multiple Parallel Strings	Tool	Shoe
12. Cementing Date								
13. •Drilled hole size								
•Est. % wash or hole enlargement								
14. Size of casing (in. O.D.)								
15. Top of liner (ft.)								
16. Setting depth (ft.)								
17. Number of centralizers used								
18. Hrs. waiting on cement before drill-out								
1st Slurry	19. API cement used:	No. of sacks ▶						
		Class ▶						
		Additives ▶						
2nd Slurry		No. of sacks ▶						
		Class ▶						
		Additives ▶						
3rd Slurry		No. of sacks ▶						
		Class ▶						
		Additives ▶						
1st	20. Slurry pumped:	Volume (cu. ft.) ▶						
		Height (ft.) ▶						
2nd		Volume (cu. ft.) ▶						
		Height (ft.) ▶						
3rd		Volume (cu. ft.) ▶						
		Height (ft.) ▶						
Total		Volume (cu. ft.) ▶						
		Height (ft.) ▶						
21. Was cement circulated to ground surface (or bottom of cellar) outside casing?								

22. Remarks

OVER ▶

Plugging Record

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

FORM W - 3
Rev. 12/92

API NO. (if available)

1. RRC District

FILE IN DUPLICATE WITH DISTRICT OFFICE OF DISTRICT IN WHICH WELL IS LOCATED WITHIN THIRTY DAYS AFTER PLUGGING

4. RRC Lease or Id. Number

2. FIELD NAME (as per RRC Records)
3. Lease Name
5. Well Number

6. OPERATOR
6a. Original Form W-1 Filed in Name of:
10. County

7. ADDRESS
6b. Any Subsequent W-1's Filed in Name of:
11. Date Drilling Permit Issued

8. Location of Well, Relative to Nearest Lease Boundaries of Lease on which this Well is located
Feet From Line and Feet From Line of the Lease
12. Permit Number

9a. SECTION, BLOCK, AND SURVEY
9b. Distance and Direction From Nearest Town in this County
13. Date Drilling Commenced

16. TYPE WELL (OIL,GAS,DRY)
Total Depth
17. If Multiple Completion List All Field Names and Oil Lease or Gas ID No's | GAS ID or OIL LEASE # | Oil - O Gas - G | WELL #
14. Date Drilling Completed

18. If Gas, Amt. of Cond. on Hand at time of Plugging
15. Date Well Plugged

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7	PLUG #8
*19. Cementing Date	9/29/96							
20. Size of Hole or Pipe in which Plug Placed (inches)								
21. Depth to Bottom of Tubing or Drill Pipe (ft.)								
*22. Sacks of Cement Used (each plug)	375							
*23. Slurry Volume Plumped (cu. ft.)	407.66							
*24. Calculated Top of Plug (ft.)	1299.37							
25. Measured Top of Plug (if tagged) (ft.)								
*26. Slurry Wt. #/Gal.	16.2							
*27. Type Cement	H							

28. CASING AND TUBING RECORD AFTER PLUGGING

29. Was any Non - Drillable Material (Other than Casing) Left in This Well ☐ Yes ☐ No

SIZE	WT. #/FT.	PUT IN WELL (ft.)	LEFT IN WELL (ft.)	HOLE SIZE (in.)

29a. If answer to above is "Yes" state depth to top of "junk" left in hole and briefly describe non - drillable material. (Use Reverse Side of Form if more space is needed.)

30. LIST ALL OPEN HOLD AND/OR PERFORATED INTERVALS

FROM	TO	FROM	TO
FROM	TO	FROM	TO
FROM	TO	FROM	TO
FROM	TO	FROM	TO
FROM	TO	FROM	TO

I have knowledge that the cementing operations, as reflected by the information found on this form, were performed as indicated by such information.

* Designates items to be completed by Cementing Company. Items not so designated shall be completed by Operator.

BILLY F. YANDELL B.F. Yandell
Signature of Cementer or Authorized Representative

HALLIBURTON ENERGY SERVICES 10/7/96
Name of Cementing Company

CERTIFICATE

I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct, and complete, to the best of my knowledge.

REPRESENTATIVE OF COMPANY TITLE DATE Phone A/C NUMBER

SIGNATURE: REPRESENTATIVE OF RAILROAD COMMISION

Plugging Record

RAILROAD COMMISSION OF TEXAS

OIL AND GAS DIVISION

FORM W - 3
Rev. 12/92

		API NO. (if available)	1. RRC District
FILE IN DUPLICATE WITH DISTRICT OFFICE OF DISTRICT IN WHICH WELL IS LOCATED WITHIN THIRTY DAYS AFTER PLUGGING			4. RRC Lease or Id Number
2. FIELD NAME (as per RRC Records)	3. Lease Name		5. Well Number
6. OPERATOR	6a. Original Form W-1 Filed in Name of:		10. County
7. ADDRESS	6b. Any Subsequent W-1's Filed in Name of:		11. Date Drilling Permit Issued
8. Location of Well, Relative to Nearest Lease Boundaries of Lease on which this Well is located	Feet From Line and Feet From Line of the Lease		12. Permit Number
9a. SECTION, BLOCK, AND SURVEY	9b. Distance and Direction From Nearest Town in this County		13. Date Drilling Commenced
16. TYPE WELL (OIL,GAS,DRY) / Total Depth	17. If Multiple Completion List All Field Names and Oil Lease or Gas ID No's	GAS ID or OIL LEASE # / Oil - O Gas - G / WELL #	14. Date Drilling Completed
18. If Gas, Amt. of Cond. on Hand at time of Plugging			15. Date Well Plugged

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7	PLUG #8
*19. Cementing Date	9/30/96							
20. Size of Hole or Pipe in which Plug Placed (inches)								
21. Depth to Bottom of Tubing or Drill Pipe (ft.)								
*22. Sacks of Cement Used (each plug)	478							
*23. Slurry Volume Plumped (cu. ft.)	521.02							
*24. Calculated Top of Plug (ft.)	0							
25. Measured Top of Plug (if tagged) (ft.)								
*26. Slurry Wt. #/Gal.	16.2							
*27. Type Cement	H							

28. CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT. #/FT.	PUT IN WELL (ft.)	LEFT IN WELL (ft.)	HOLE SIZE (in.)

29. Was any Non - Drillable Material (Other than Casing) Left in This Well ☐ Yes ☐ No

29a. If answer to above is "Yes" state depth to top of "junk" left in hole and briefly describe non - drillable material. (Use Reverse Side of Form if more space is needed.)

30. LIST ALL OPEN HOLD AND/OR PERFORATED INTERVALS

FROM	TO	FROM	TO
FROM	TO	FROM	TO
FROM	TO	FROM	TO
FROM	TO	FROM	TO
FROM	TO	FROM	TO

I have knowledge that the cementing operations, as reflected by the information found on this form, were performed as indicated by such information.

* Designates items to be completed by Cementing Company. Items not so designated shall be completed by Operator.

BILLY F. YANDELL B.F. Yandell
Signature of Cementer or Authorized Representative

HALLIBURTON ENERGY SERVICES 10/7/96
Name of Cementing Company

CERTIFICATE

I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct, and complete, to the best of my knowledge.

REPRESENTATIVE OF COMPANY   TITLE   DATE   Phone A/C NUMBER

SIGNATURE: REPRESENTATIVE OF RAILROAD COMMISION

Plugging Record

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

FORM W - 3
Rev. 12/92

API NO. (if available)	1. RRC District

FILE IN DUPLICATE WITH DISTRICT OFFICE OF DISTRICT IN WHICH WELL IS LOCATED WITHIN THIRTY DAYS AFTER PLUGGING

4. RRC Lease or Id Number

FIELD NAME (as per RRC Records)	3. Lease Name	5. Well Number
OPERATOR	6a. Original Form W-1 Filed in Name of:	10. County
ADDRESS	6b. Any Subsequent W-1's Filed in Name of:	11. Date Drilling Permit Issued
Location of Well, Relative to Nearest Lease Boundaries of Lease on which this Well is located	Feet From Line and Feet From Line of the Lease	12. Permit Number
9a. SECTION, BLOCK, AND SURVEY	9b. Distance and Direction From Nearest Town in this County	13. Date Drilling Commenced

6. TYPE WELL (OIL,GAS,DRY)	Total Depth	17. If Multiple Completion List All Field Names and Oil Lease or Gas ID No's	GAS ID or OIL LEASE #	Oil - O Gas - G	WELL #	14. Date Drilling Completed
18. If Gas, Amt. of Cond. on Hand at time of Plugging						15. Date Well Plugged

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7	PLUG #8
*19. Cementing Date	10/1/96							
20. Size of Hole or Pipe in which Plug Placed (inches)								
21. Depth to Bottom of Tubing or Drill Pipe (ft.)								
*22. Sacks of Cement Used (each plug)	60							
*23. Slurry Volume Plumped (cu. ft.)	65.4							
*24. Calculated Top of Plug (ft.)	0							
25. Measured Top of Plug (if tagged) (ft.)								
*26. Slurry Wt. #/Gal.	16.2							
*27. Type Cement	H							

28. CASING AND TUBING RECORD AFTER PLUGGING

29 Was any Non - Drillable Material (Other than Casing) Left in This Well ☐ Yes ☐ No

SIZE	WT. #/FT.	PUT IN WELL (ft.)	LEFT IN WELL (ft.)	HOLE SIZE (in.)

29a. If answer to above is "Yes" state depth to top of "junk" left in hole and briefly describe non - drillable material. (Use Reverse Side of Form if more space is needed.)

30. LIST ALL OPEN HOLD AND/OR PERFORATED INTERVALS

FROM	TO	FROM	TO
FROM	TO	FROM	TO
FROM	TO	FROM	TO
FROM	TO	FROM	TO
FROM	TO	FROM	TO

I have knowledge that the cementing operations, as reflected by the information found on this form, were performed as indicated by such information.

* Designates items to be completed by Cementing Company. Items not so designated shall be completed by Operator.

BILLY F. YANDELL B.F. Yandell
Signature of Cementer or Authorized Representative

HALLIBURTON ENERGY SERVICES 10/7/96
Name of Cementing Company

CERTIFICATE

I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct, and complete, to the best of my knowledge.

REPRESENTATIVE OF COMPANY   TITLE   DATE   Phone A/C NUMBER

SIGNATURE: REPRESENTATIVE OF RAILROAD COMMISION

APPENDIX C

CORRESPONDENCE

File ECC Job 96014

TEXAS NATURAL RESOURCE CONSERVATION COMMISSION

Protecting Texas by Reducing and Preventing Pollution

June 28, 1996

I. O. Coleman, Jr.
Hoechst Celanese, Chemical Group
Bay City Plant
P. O. Box 509
Highway 3057
Bay City, TX 77404-0509

Re: Approval of Closure Procedures, Permits No. WDW-32 and WDW-49, Bay City, Texas

Dear Mr. Coleman, Jr.:

The staff has reviewed your letter of June 10 detailing the closure procedures previously approved January 8, 1996 of the above referenced wells and finds that it meets the requirements outlined in 30 TAC §331.46 (Closure Standards). Please submit the Closure Report as required by §331.46(m) within 30 days of completion of closure of the final well since both wells will be closed during the continuous series using the same equipment. Please also provide evidence of the deed recording as required by §331.46(l) prior to a request of revocation of the permit.

Your letter also certifies that neither well had been operated since the last MIT in October, 1995 for WDW-32 and in March, 1996 for WDW-49, and staff agrees that will suffice as final MIT testing prior to closure.

It is also requested that we be kept up-dated on the exact date of closure operations so that a staff member may schedule to be present. Questions regarding this matter should be directed to me at (512) 239-6196, correspondence may be sent to me at Mail Code, MC-131 at the TNRCC address.

Sincerely,

Jim L Boswell

Jim L. Boswell, Permit Coordinator
Underground Injection Control Team
UIC, Uranium, & Radioactive Waste Section
Industrial & Hazardous Waste Division

cc: Brian Graves, EPA Region 6

96014

Hoechst Celanese

Chemical Group
Hoechst Celanese Corporation
Bay City Plant
PO Box 509
Highway 3057
Bay City, TX 77404-0509

June 10, 1996
IOC-033-96

FEDERAL EXPRESS

Mr. Jim L. Boswell, Permit Coordinator
Underground Injection Control Team
UIC, Uranium & Radioactive Waste Section
TX Natl Resource Conservation Commission
12100 Park 35 Circle
Austin, TX 78753

RE: Closure Procedures for Class I Injection Wells
WDW-32 (Plant Well #2) and WDW-49 (Plant Well #4)
Hoechst Celanese Chemical Group, Ltd.
Bay City Plant, Bay City, TX

Dear Mr. Boswell:

Hoechst Celanese Chemical Group, Ltd. hereby submits the attached closure procedures (2 copies) for Class I Injection Wells WDW-32 (Well #3) and WDW-49 Well #4) located at the Bay City Plant. The attached information is intended to update the closure plans previously approved by the TNRCC on January 8, 1996.

We propose to conduct field operations in a continuous series of events with a minimal delay as equipment is moved from Injection Well WDW-32 to Injection Well WDW-49. As documented in the attached schedule, field operations should start early in September, 1996.

You will be advised as the work plans and schedule are finalized. If you have any questions, please call me at 409-241-4197.

Sincerely,

I. O. Coleman, Jr. /cjs

I. O. Coleman, Jr.
Staff Environmental Chemist

IOC/cjs
attachment

Hoechst

cc: w/o attachment

Mr. Ben Knape, Chief
Underground Injection Control Unit
UIC, Uranium & Radioactive Waste Section
Industrial and Hazardous Waste Division
TX Natl Resource Conservation Commission
P. O. Box 13087ircle
Austin, TX 78711-3087

Mr. Charles J. Green, Geologist
TX Natl Resource Conservation Comm.
Underground Injection Control Team
UIC, Uranium & Radioactive Waste Section
Industrial and Hazardous Waste Division
P. O. Box 13087
Austin, TX 78711-3087

bcc: w/o attachment
Via e-mail

C. R. Pennington
W.G. Cornman
D. Peters
B. L. Fritz
B. R. Hightower
J. V. Anderson
C. J. Griffith
R. S. O'Neal

Mr. Tom Jones
ECO Solutions, Inc.
9800 Richmond Ave. , Ste 320
Houston, TX 77042-4519

bcc: w/attachment

W. E. Dentler → P. H. Richardson → R. J. Johnston → G. J. McCarthy
H. R. Horton → B. S. Barrington
A. Conley-Pitchell - Bridgewater
Environmental File No.: 203.20

SOLUTIONS, INC.

HOECHST CELANESE CHEMICAL GROUP, LTD.

CLOSURE PROCEDURES AND SCHEDULE

INJECTION WELLS

WDW-32 (WELL #3) AND WDW-49 (WELL #4)

ECO Solutions, Inc.
9800 Richmond Avenue
Suite 320
Houston, TX 77042
(713) 780-1955
Fax (713) 780-1955

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HOECHST CELANESE CHEMICAL GROUP, LTD.
CLOSURE PLAN FOR INJECTION WELLS
WDW-32 (WELL #3) AND WDW-49 (WELL #4)

BACKGROUND

In a letter to Hoechst Celanese Chemical Group, Ltd. (Hoechst Celanese) dated January 8, 1996, the Texas Natural Resource Conservation Commission (TNRCC) granted approval to the closure plans for Class I injection wells WDW-14, WDW-32, WDW-49 and WDW-110 located at the Bay City Plant. Field operations to close injection well WDW-14 (well #2) were completed on March 13, 1996.

Hoechst Celanese plans to properly close two (2) of the remaining three (3) Class I injection wells starting in September, 1996. Injection well WDW-32 (well #3) will be closed first and injection well WDW-49 (well #4) closed second. It is planned that the field operations associated with these two well closures will be accomplished as a single continuous sequence of events with little delay as the equipment is moved from one well location to the next.

Two (2) closure plans are attached which follow the procedures previously approved by the TNRCC. The only changes reflect the site specific conditions and depths unique to each well. Although no additional regulatory approvals are required, the attached plans are submitted for your information. A preliminary closure schedule is also attached. Well schematics were included with the original closure plan submitted to the TNRCC and have not changed.

MECHANICAL INTEGRITY TESTING

As stated in the January 8, 1996 TNRCC approval letter, WDW-14 (well #2) required no additional mechanical integrity testing since the well had not operated following its last successful mechanical integrity demonstration. Hoechst Celanese requests that the TNRCC confirm that no additional mechanical integrity testing will be required on WDW-32 (well #3) and WDW-49 (well #4). The last mechanical integrity and falloff testing was completed on WDW-32 (well #3) in October, 1995 and on WDW-49 (well #4) in March, 1996. Both injection wells were brined in and the flowlines disconnected following the testing. No waste injection has occurred since those dates.

SUBMITTAL OF CLOSURE REPORT

As required by 30 TAC §331.46(m), the closure report must be submitted within 30 days of completion of closure. A clarification is requested on the timing of the closure report. Since injection wells WDW-32 (well #3) and WDW-49 (well #4) are to be closed in a continuous sequence of field operations, it is requested that the closure reports for both wells be submitted 30 days following the completion of closure of the second well, or WDW-49 (well #4). This schedule will allow the field certification information to be obtained and integrated into the respective reports in a timely manner.

INJECTION WELL WDW-32 (WELL # 3)
CLOSURE PROCEDURES

1) Prepare well location for field operations. Remove flow lines, monitoring equipment, and instrumentation. Line and dike surface area surrounding wellsite in the area where the workover rig, pumps, tanks and pipe racks will be placed.

2) Notify TNRCC representative of anticipated start of field operations.

3) Move in and rig up workover rig and peripheral equipment.

4) Pull seal assembly out of packer and triple rinse injection string and flush annular area with 9.8 ppg brine.

5) Pull out of the hole laying down injection string and TIW seal assembly on pipe racks. HCCG personnel will remove injection string and TIW seal assembly from wellsite.

6) Pick up casing scraper and work string. Go in hole with casing scraper to the top of the injection packer at 3192' ±. Pull out of the hole with same.

7) Move in and rig up wireline unit to set cement retainer. Pick up junk basket and gauge ring and go in the hole to the top of the injection packer. Pull out of the hole with the junk basket and gauge ring. Go in the hole with wireline set cast iron cement retainer and set inside the 9+5/8" casing at 3182' ±, or approximately 10' above the top of the injection packer. Pull out of the hole and rig down wireline unit.

8) Notify TNRCC representative 24 hours prior to start of cementing operations to witness placement of cement plugs.

9) Pick-up cement retainer shifting assembly with work string and go in the hole with same. Engage cement retainer with shifting assembly and test annulus to 500 psi to confirm that the cement retainer is properly set.

10) Rig up Halliburton, or equivalent service company, to squeeze cement (permanently abandon) the injection zone. Pumping through retainer fill injection interval with high compressive strength cement slurry. Close cement retainer and disengage from same. Leave a 50' ± column of cement above cement retainer and pull out of the hole with shifting assembly.

11) Pick up section mill and drill collars on work string and go in the hole with same. Mill out approximately 50' section of 9+5/8" casing above the top of the cement column. Pull out of the hole and remove section mill.

12) Pick up underreamer and drill collars and go in the hole with same. Underream sectioned interval out to approximately 14" diameter borehole. Pull out of the hole with underreamer.

13) Go in the hole open-ended to set cement plug #2. The plug will extend up across the sectioned interval and an additional 300' - 400' above the section. Rig up Halliburton, or equivalent, and set balanced cement plug with high compressive strength cement. Pull out of the hole and wait on cement plug #2 to cure (approximately 12 hours).

14) Go in the hole with 8+3/4" drill bit and drill pipe to confirm the top of the cement. "Dress off" top of plug #2 to confirm cement has had sufficient time to properly cure.

15) Rig up Halliburton, or equivalent, and set cement plug #3 with high compressive strength cement. Set balanced cement plug. Cement column to extend from the previous plug up to 1500' ± or approximately 200' beneath the base of surface casing. Pull out of the hole and wait on cement plug #3 to cure (approximately 12 hours).

16) Go in the hole with 8+3/4" drill bit and drill pipe to confirm the top of cement column. "Dress off" the top of plug #3 to confirm that cement has had sufficient time to properly cure. Pull out of the hole.

17) Move in and rig up wireline truck to perforate for squeeze job at the base of the surface casing. Perforate the protection casing 2' at 4 shots per foot (8 shots) with top at 1312' ±, or approximately 10' beneath the surface casing seat at 1302' ±. Pull out of the hole and rig down wireline unit.

18) Rig up Halliburton, or equivalent, and set cement plug #4 with high compressive strength cement. Set balanced cement plug. Cement column will extend from the top of plug #3 back to the surface. Pull out of the hole. Apply pressure to cement column to squeeze cement out through the perforations. Wait on cement plug #4 to cure (approximately 12 hours).

19) Go in the hole with 8+3/4" drill bit and drill pipe to confirm the top of cement column. "Dress off" the top of plug #4 to confirm that cement has had sufficient time to properly cure. Fill balance of protection casing with high compressive strength cement as required. Pull out of the hole and lay down work string. Wash out blowout preventors.

20) Rig down and release workover rig. Cut off casings at grade and weld 1/2" steel plate over all casing strings. Inscribe plate with well identification and other pertinent data as required.

21) Prepare summary report for submittal to TNRCC and USEPA Region 6.

INJECTION WELL WDW-49 (WELL # 4)
CLOSURE PROCEDURES

1) Prepare well location for field operations. Remove flow lines, monitoring equipment, and instrumentation. Line and dike surface area surrounding wellsite in the area where the workover rig, pumps, tanks and pipe racks will be placed.

2) Notify TNRCC representative of anticipated start of field operations.

3) Move workover rig and peripheral equipment from WDW-32 (well #3) to WDW-49 (well #4)

4) Pull seal assembly out of packer and triple rinse injection string and flush annular area with 9.8 ppg brine.

5) Pull out of the hole laying down injection string and TIW seal assembly on pipe racks. HCCG personnel will remove injection string and TIW seal assembly from wellsite.

6) Pick up casing scraper and work string. Go in hole with casing scraper to the top of the injection packer at 3316' ±. Pull out of the hole with same.

7) Move in and rig up wireline unit to set cement retainer. Pick up junk basket and gauge ring and go in the hole to the top of the injection packer. Pull out of the hole with the junk basket and gauge ring. Go in the hole with wireline-set cast iron cement retainer and set inside the 7+5/8" casing at 3306' ±, or approximately 10' above the top of the injection packer. Pull out of the hole and rig down wireline unit.

8) Notify TNRCC representative 24 hours prior to start of cementing operations to witness placement of cement plugs.

9) Pick-up cement retainer shifting assembly with work string and go in the hole with same. Engage cement retainer with shifting assembly and test annulus to 500 psi to confirm that the cement retainer is properly set.

10) Rig up Halliburton, or equivalent service company, to squeeze cement (permanently abandon) the injection zone. Pumping through retainer fill injection interval with high compressive strength cement slurry. Close cement retainer and disengage from same. Leave a 50' ± column of cement above cement retainer and pull out of the hole with shifting assembly.

11) Pick up section mill and drill collars on work string and go in the hole with same. Mill out approximately 50' section of 7+5/8" casing above the top of the cement column. Pull out of the hole and remove section mill.

12) Pick up underreamer and drill collars and go in the hole with same. Underream sectioned interval out to approximately 10" diameter borehole. Pull out of the hole with underreamer.

13) Go in the hole open-ended to set cement plug #2. The plug will extend up across the sectioned interval and an additional 300' - 400' above the section. Rig up Halliburton, or equivalent, and set balanced cement plug with high compressive strength cement. Pull out of the hole and wait on cement plug #2 to cure (approximately 12 hours).

14) Go in the hole with 6 ¾" drill bit and drill pipe to confirm the top of the column of cement. "Dress off "top of plug #2 to confirm cement has had sufficient time to properly cure.

15) Rig up Halliburton, or equivalent, and set cement plug #3 with high compressive strength cement. Set balanced cement plug. Cement column to extend from the previous plug up to 1500' ±, or approximately 200' beneath the base of surface casing. Pull out of the hole and wait on cement plug #3 to cure (approximately 12 hours).

16) Go in the hole with 6+¾" drill bit and drill pipe to confirm the top of cement column. "Dress off " the top of plug #3 to confirm that cement has had sufficient time to properly cure. Pull out of the hole.

17) Move in and rig up wireline truck to perforate for squeeze job at the base of the surface casing. Perforate the protection casing 2' at 4 shots per foot (8 shots) with top at 1400' ± or approximately 10' beneath the surface casing seat at 1389' ±. Pull out of the hole and rig down wireline unit.

18) Rig up Halliburton, or equivalent, and set cement plug #4 with high compressive strength cement. Set balanced cement plug. Cement column will extend from the top of plug #3 back to the surface. Pull out of the hole. Apply pressure to cement column to squeeze cement out through the perforations. Wait on cement plug #4 to cure (approximately 12 hours).

19) Go in the hole with 6 ¾" drill bit and drill pipe to confirm the top of cement column. "Dress off" the top of plug #4 to confirm that cement has had sufficient time to properly cure. Fill balance of protection casing with high compressive strength cement as required. Pull out of the hole and lay down work string. Wash out blowout preventors.

20) Rig down and release workover rig. Cut off casings at grade and weld 1/2" steel plate over all casing strings. Inscribe plate with well identification and other pertinent data as required.

21) Prepare summary report for submittal to TNRCC and USEPA Region 6.

22) Project Complete

ATTACHMENT 1

CLOSURE SCHEDULE

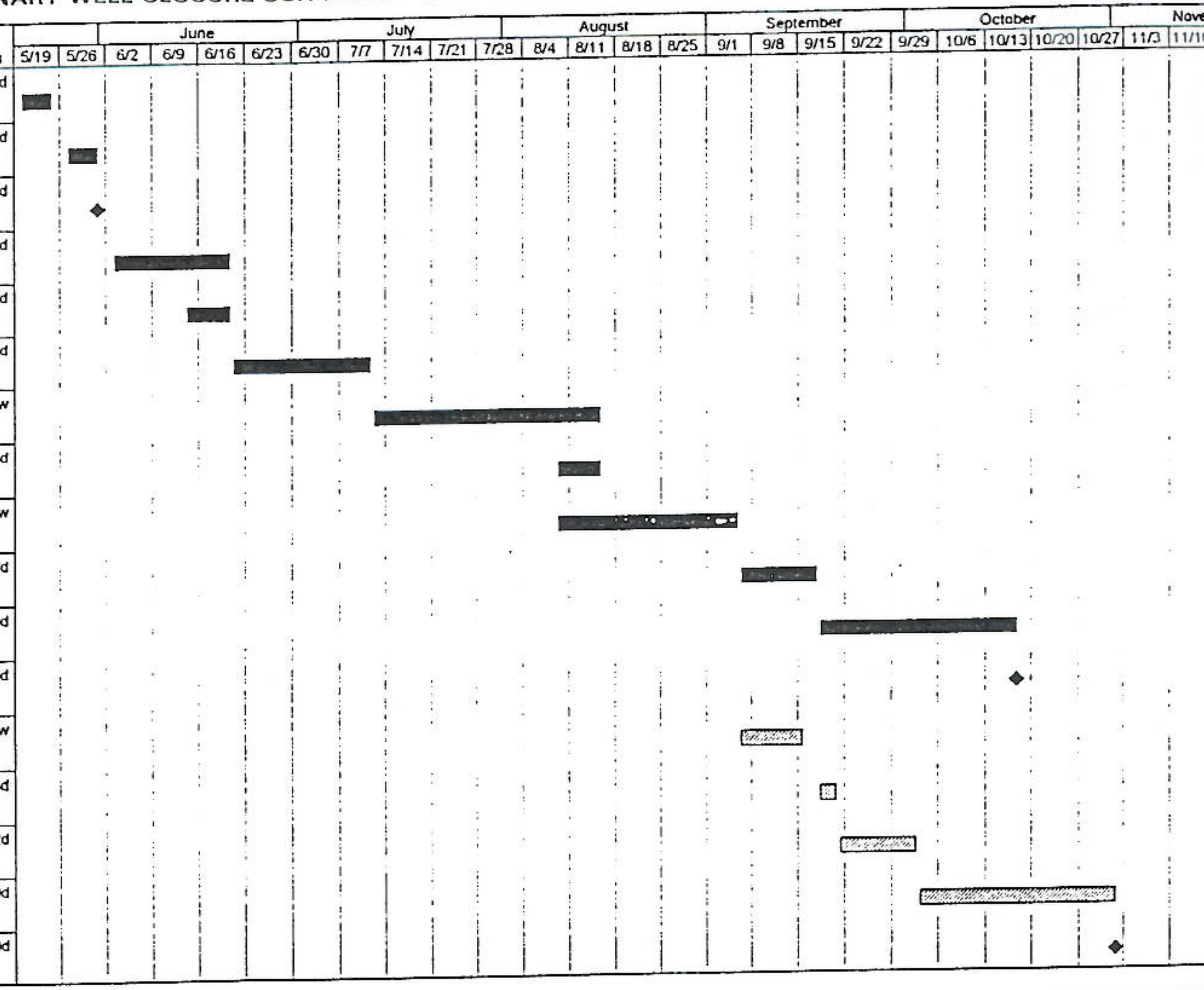
WDW-32 (WELL #3)

WDW-49 (WELL #4)

SOLUTIONS, INC.

HOECHST CELANESE CHEMICAL GROUP, LTD
BAY CITY, TEXAS PLANT
PRELIMINARY WELL CLOSURE SCHEDULE - WDW-32 WDW-49

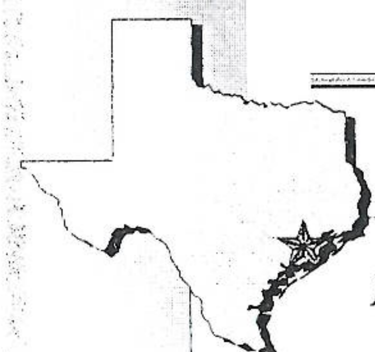
NO.	Name	Work Days
1	Prepare updated closure procedures for TNRCC	5d
2	Review by HCCG & finalize by ECO	5d
3	Submit Procedures To TNRCC	0d
4	TNRCC Review and approval	14d
5	Solicit Vendor Quotes	5d
6	Obtain Vendor Quotes - Prepare final recommendations	15d
7	Identify rig availability & schedule	5w
8	Finalize procedures cost & schedule	5d
9	Site Preparations For Field Operations	4w
10	Field Operations To Close WDW-32	12d
11	Prepare Final Closure Report	30d
12	Submit Final Closure Report To TNRCC	0d
13	Prepare location for closure operations	2w
14	Move rig & equipment to WDW-49	3d
15	Field Operations To Close WDW-49	12d
16	Prepare Final Closure Report	30d
17	Submit Final Closure Report To TNRCC	0d



APPENDIX D
FINAL MECHANICAL INTEGRITY TESTING REPORT (TEXT ONLY)
WDW-32 (WELL #3)

SOLUTIONS, INC.

Final Report



Hoechst Celanese Chemical Group, Inc.
Bay City, Texas
MIT/Fall-off Report
Injection Well WDW-32 (Well No. 3)
October 24 - 26, 1995

ECO Solutions, Inc.
9800 Richmond Avenue
Suite 320
Houston, Texas 77042
(713) 780-1955
FAX (713) 780-0870

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APPENDICES

1.0 INTRODUCTION AND EXECUTIVE SUMMARY

1.1 INTRODUCTION

Hoechst Celanese Chemical Group, Inc. (HCCG) contracted ECO Solutions, Inc. (ECO) to perform the annual mechanical integrity testing on their Class I nonhazardous injection well, WDW-32 (Well No. 3), located at their Bay City facility. A schematic drawing of WDW-32 is included as Figure 1. The attached report details the data and test results associated with the mechanical integrity testing.

The following provides an overview of the key elements of the testing on WDW-32 (Well No. 3).

- An Annulus Pressure Test (APT) was conducted to satisfy the annual mechanical integrity test (MIT) requirements of the Texas Natural Resource Conservation Commission's (TNRCC), Underground Injection Control (UIC) Program.

- A Radioactive Tracer (RAT) survey was conducted to satisfy the annual MIT requirements of the TNRCC.

- Bottom Hole Pressure (BHP) falloff testing was conducted to satisfy the annual ambient monitoring requirements of the U.S. Environmental Protection Agency (EPA) and the TNRCC

HCCG personnel contacted the TNRCC personnel to inform them of the MIT schedule on WDW-32 and whether a field inspector would be present. TNRCC personnel informed HCCG that no field inspector would be present for this particular MIT.

The APT on WDW-32 (Well No.3) was conducted on Thursday, October 26, 1995, and was witnessed by Mr. Wesley Smith of ECO and Mr. Ray Horton of HCCG. The RAT was conducted on Thursday, October 26, 1995, and was witnessed by Mr. Wesley Smith of ECO and Mr. Ray Horton of HCCG.

The BHP/falloff test was conducted on Tuesday, October 24, 1995 through Thursday, October 26, 1995 and was witnessed by Mr. Wes Smith of ECO and Mr. Ray Horton of HCCG.

1.2 EXECUTIVE SUMMARY

Based on the successful results of the MIT conducted on October 26, 1995 on WDW-32, HCCG is able to return WDW-32 to injection service if required. Also, based on a decision by HCCG's Bay City management WDW-32 was brined in on October 27, 1995 using 150 barrels (42 gallons/barrel) of 10 pound per gallon (ppg) brine and left shut-in until closure operations are commenced. A summary of the results of the MIT and BHP/Falloff survey are as follows:

Radioactive Tracer Survey

The analysis of the RAT survey performed on October 26, 1995 demonstrated that no upward fluid movement from the injection interval is occurring. Additionally, this determination can be made as a result of (1) the favorable comparison of the before and after base gamma ray surveys, (2) the two multiple pass tracer surveys and the two stationary surveys conducted 20' above the packer path. All four tests showed no evidence of upward migration. This interpretation was supported by an independent evaluation provided by Atlas Wireline Services (Atlas) and is included in Appendix A together with the RAT log.

Annulus Pressure Test

A demonstration of internal mechanical integrity was supported by an APT conducted on October 26, 1995. The annulus was pressurized to a maximum of 1109 pounds per square inch gauge (psig). The APT was monitored for eighty minutes. During the final 30 minutes the pressure loss was measured from 1102 to 1101 psig, or 1 pound per square inch (psi) (0.1%), which is well within the 5% pressure loss criteria set by the TNRCC. The APT plot is included in Appendix B.

Bottom Hole Pressure Falloff Survey

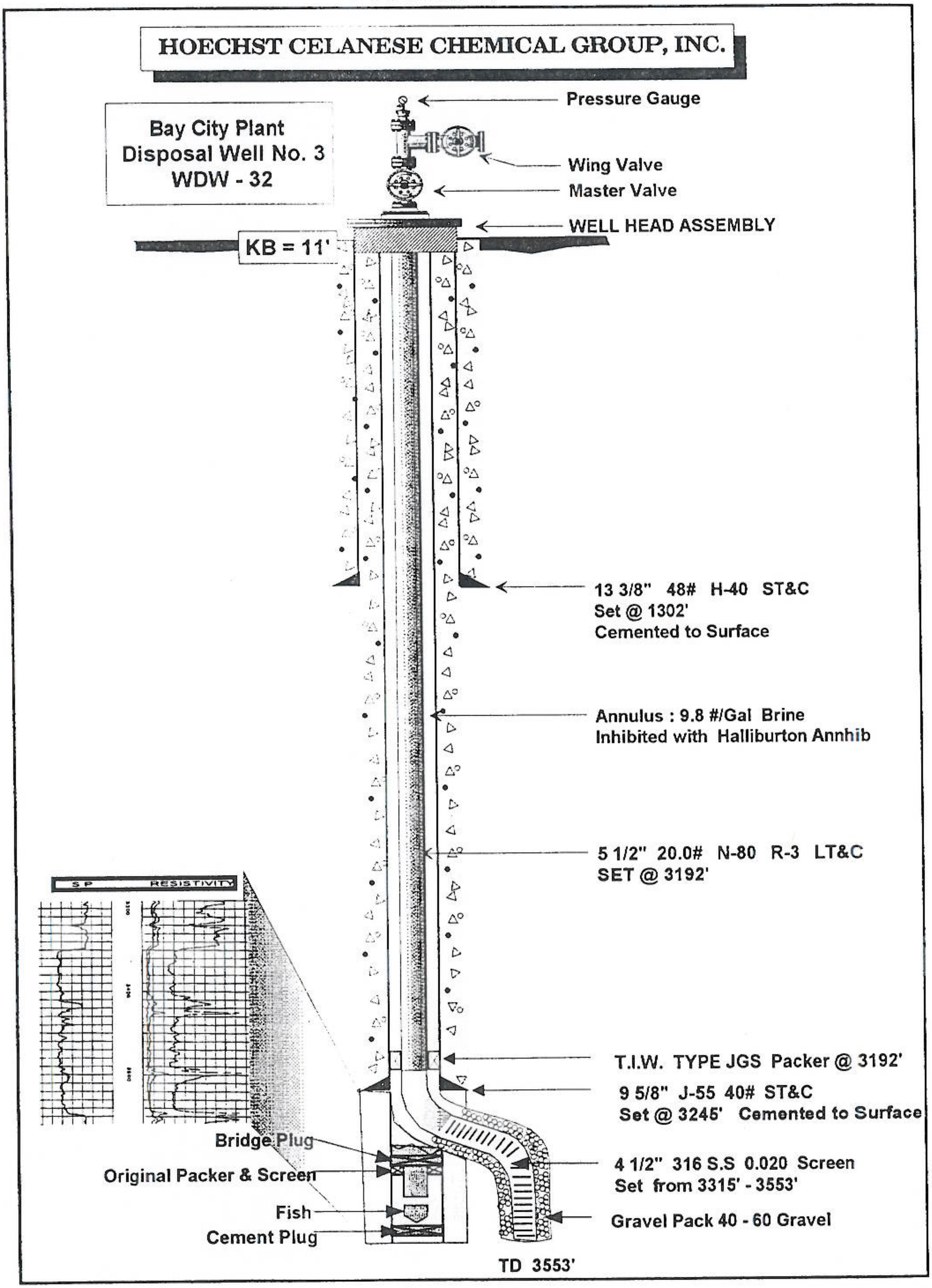
Waste stream fluid was injected into WDW-32 at a steady rate of 150 gpm for 96 hours and was shut-in for a total of 34 hours. The shape of both the pressure and pressure derivative curves on a log-log plot at early times are reasonable, but are similar to the test conducted in January 1995. A full discussion of the falloff analyses is presented in Section 4.0.

Overall Field Work Conclusion

All field work associated with the MIT/BHP/Falloff survey on HCCG's WDW-32 at the Bay City Plant conducted from October 24 through 27, 1995 was successfully completed. WDW-32 is considered to be mechanically sound at this time and is suitable for further use as a Class I waste injection well.

In accordance with the TNRCC/UIC Program, 31TAC, 331.4 and 331.43, the mechanical integrity test conducted on WDW-32 demonstrated that (1) "there is no significant leak in the casing, tubing or packer" and (2) "there is no significant fluid movement into an underground source of drinking water (USDW) through vertical channels adjacent to the injection borehole."

FIGURE 1


HOECHST CELANESE CHEMICAL GROUP, INC.
Bay City Plant
Disposal Well No. 3
WDW - 32
Pressure Gauge
Wing Valve
Master Valve
WELL HEAD ASSEMBLY
KB = 11'
13 3/8" 48# H-40 ST&C
Set @ 1302'
Cemented to Surface
Annulus : 9.8 #/Gal Brine
Inhibited with Halliburton Annhib
5 1/2" 20.0# N-80 R-3 LT&C
SET @ 3192'
SP
RESISTIVITY
T.I.W. TYPE JGS Packer @ 3192'
9 5/8" J-55 40# ST&C
Set @ 3245' Cemented to Surface
Bridge Plug
Original Packer & Screen
Fish
Cement Plug
4 1/2" 316 S.S 0.020 Screen
Set from 3315' - 3553'
Gravel Pack 40 - 60 Gravel
TD 3553'

2.0 FIELD OPERATIONS SUMMARY

2.1 BOTTOM HOLE PRESSURE FALLOFF SURVEY

Friday, October 20, 1995

Brought injection up to 150 gallons per minute (gpm) at 1800 hours.

Saturday, October 21 - Monday, October 23, 1995

Continued injecting at steady rate of 150 gpm.

Tuesday, October 24, 1995

Arrived at plant location at 0700, checked in with front gate. After meeting with Mr. Paul Richardson and Mr. Ray Horton, went to site of WDW-32 at 0740 hours. Effluent was being injected at well head pressure (WHP) = 610 pounds per square inch gauge (psig). At 0830 hours Mr. Ray Horton processed Wes Smith (ECO), Doug Beall and Mike Staley Milton M. Cooke Company (Cooke) through HCCG's contractor safety orientation check list. Cooke wireline rigged up on well. NOTE: All depths are referenced to rotary drive bushing (RKB) at 11' above ground level.

WDW-110 (Well No. 1-A)	out of service
WDW-14 (Well No. 2)	out of service
WDW-32 (Well No. 3)	active/injecting
WDW-49 (Well No. 4)	out of service

Checked with Paul Richardson @ control room. WDW-32 injecting approximately 150 gpm. At 0840 made run through gauge calibrations:

EPG 520 Serial # 85954 (Surface ReadOut) - Range 0 - 2500 psia.
EMS 725 Serial # 79993 (Back-up, Memory gauge)

Met with Ray Horton at 0900 hours to review test procedures and current condition of well. At 0910 hours placed tool string in lubricator (18 ft. length) as follows:

Length	Description
0.5'	Cable head
1'	Collar locator
1-1/2'	EPG 520 (SRO gauge)
4-1/2'	EPG 725 (memory gauge)
5'	weight bar
5'	weight bar

At 1045 hours opened master valve, pressured up lubricator, and prepared to go in hole. At 1056 hours check SRO gauge (WHP = 613.66 pounds per square inch absolute (psia)), going in hole. Prepare to tie into packer (RAT survey) with casing collar locator (CCL). Turned on CCL, making passes correlating strip chart. At 1200 hours tool @ 3204 ft., begin logging up hole.

Finished CCL log at 1140 hours, set gauges @ 3192 feet. Monitor injection bottom hole pressure and temperature.

At 1244 hours began monitoring injection period of test.

Injection rate	150 gpm
Down hole injection pressure	1843 psia
Surface injection pressure	610 psig

Continue monitoring injection period of test. Readings at 1600 hours:

Injection rate	150 gpm
Down hole injection pressure	1843 psia
Surface injection pressure	610 psig

Met with shift supervisor, prepared to shut-down injection operations. Stop injection pumps at 1800 hours and begin fall-off test. Double block @ injection line manifold.

Final injection conditions:

Injection rate	150 gpm
Down hole injection pressure	1842.22 psia
Surface injection pressure	610 psig

Continue monitoring fall-off period of test at 2200 hours.

Shut-in down hole pressure	1472.16 psia
Surface	72 psig

Wednesday, October 25, 1995

Continue monitoring fall-off period of test (0800 hours).

Shut-in down hole pressure	1469.80 psia
Surface shut-in pressure	69 psig

2200 hours continue monitoring fall-off period of test.

Shut-in down hole pressure	1469 psia
Surface shut-in pressure	68 psig

Thursday, October 26, 1995

0200 hours continue monitoring fall-off period of test.

Shut-in down hole pressure	1468 psia
Surface shut-in pressure	67 psig

At 0400 hours stop recording downhole pressures, download ASCII data file, and perform preliminary analysis. Pull out of hole with tool, making static gradient stops (15 minutes/stop) at 3000', 2500', 2000', 1500', 1000', 500' and surface.

Final shut-in pressures/temperature	
Shut-in down hole pressure	1468 psia
Shut-in down hole temperature	104 Deg. F
Surface shut-in pressure	67 psig

At 0700 hours gauges in lubricator and end of pressure falloff survey. Begin rigging down wireline equipment. Cooke crew leaving location at 0930 hours.

2.2 MECHANICAL INTEGRITY TEST

Thursday, October 26, 1995

At 0730 hours Wes Smith of ECO and Ray Horton of HCCG met at the front entrance to the Bay City plant and traveled to WDW-32 and met with Mr. Wilson Cupples with HCCG's instrument group. WDW-32 was shut-in with 200 psig on the tubing gauge and 67 psig on the annulus. Also, HCCG's site recorder was operational. A certified calibrated pressure instrument, Eaton Pressure Sensor, Type UPC 5000 BACB with ranges from zero to 400, zero to 1,000 and zero to 2,000 psig, was installed onto the annulus outlet. NOTE: The zero to 2,000 psig range was utilized for this test. HCCG personnel pressurized the annulus system using nitrogen. The annulus was tested to a maximum pressure of 1109 psig. The annulus was monitored for 80 minutes. During the final 30 minute period, the pressure loss on the annulus was measured from 1102 to 1101 psig, or 1 psi (0.1%). After completion of the APT, the nitrogen gas was bled off and the annulus pressure lowered to 175 psig. WDW-32 was left shut-in.

At 1030 hours Atlas Wireline Service (Atlas) personnel arrived at HCCG's Bay City plant, checked through security and Atlas' personnel went through safety orientation. Moved in and rigged up Atlas' wireline unit including radioactive (RA) tools on WDW-32. At 1350 hours started the RAT survey as witnessed by Mr. Ray Horton of HCCG and Mr. Wes Smith of ECO. Ran tool to a maximum depth of 3250', or slightly above the disposal interval, due to damaged tubulars located immediately below this depth. Ran base gamma ray (GR) log, a short repeat section and one statistical check. Ran multiple pass survey from 3250' to 2900' with an injection rate of 50 gpm, depicting that all injected fluid was entering the lower injection interval. Repeated multiple pass survey and obtained similar positive results. Set the RAT tool at 3172' for a stationary survey, injected a RA at the same injection rate and monitored for 20 minutes with no upward flow indicated. Repeated stationary log with same results. Ran the final baseline GR log from 3250' to 2900' with no hot spots indicated. Completed the RAT survey at 1720 hours and pulled the tool out of the hole. Rigged down Atlas and moved the unit off site. WDW-32 was left shut-in. Note: Plan to brine in WDW-32 on October 27, 1995.

3.0 MECHANICAL INTEGRITY TESTING

3.1 ANNULUS PRESSURE TEST

An APT was conducted on Thursday, October 26, 1995 in order to demonstrate internal mechanical integrity. The APT was witnessed by Mr. Ray Horton of HCCG and Mr. Wesley Smith of ECO. The annulus was pressurized to a maximum pressure of 1109 psig with 67 psig on the tubing. The APT was monitored for eighty (80) minutes using a certified calibrated pressure gauge and facility recorder. During the final 30 minutes the pressure loss was measured from 1102 to 1101 psig, or 1 psi (0.1%), which was well within the 5% pressure loss criteria set by the TNRCC. An APT plot is included in Appendix B.

3.2 RADIOACTIVE TRACER SURVEY

On Thursday, October 26, 1995 a RAT survey was conducted by Atlas to insure that all fluids are entering the injection interval. Analysis of the RAT showed no upward fluid movement. Atlas and ECO conducted the RAT as follows:

1. Ran API gamma-ray (GR) tie-in strip.
2. Ran initial baseline GR log from 3250' to 2900'.
3. Ran repeat gamma-ray log from 3250' to 3000' to confirm tool repeatability.
4. Ran 5-minute statistical check at 3172'.
5. Made multiple pass survey #1 with RA slug ejected at 2900' and a pump rate of 50 gpm.
6. Made multiple pass survey #2 with a RA slug ejected at 2800' and a pump rate of 50 gpm.
7. Ran stationary survey #1 at 3172'. Watched RA slug pass tool and monitored for 20 minutes. Pump rate 50 gpm.
8. Ran stationary survey #2 at 3172'. Watched RA slug pass tool and monitored for 20 minutes. Pump rate 50 gpm.
9. Ran after survey base log from 3250' to 2900'.

3.3 ESTIMATED TIME TO RUN STATIONARY SEQUENCE

The purpose of the estimate is to calculate the "worst case" time for the radioactive slug to move from the GR tool (1) down the tubing, (2) into the screen, and (3) up the liner/casing/borehole annulus to the tool depth.

Basic Data:

Capacities:	5-1/2" tubing	-	0.9314 gal/ft.
	4-1/2" screen	-	0.653 gal/ft.
	4-1/2" screen x 12-1/4" borehole	-	5.296 gal/ft.
	9-5/8" casing x 12-1/4" borehole	-	2.343 gal/ft.
Pump Rate:	50 gpm		

Note: RAT detection tool was held stationary at 3172 feet, or 143 feet above the top of the screened liner.

Worst Case Calculations:

Volumes:	Tubing	- 20 ft. x 0.9134 gal/ft.	=	18.6
	Screen	- 123 ft. x 0.653 gal/ft.	=	80.3
	Screen/borehole	- 123 ft. x 5.296 gal/ft.	=	651.4
	Casing/borehole	- 20 ft. x 2.343 gal/ft.	=	46.9
		TOTAL		797.2 gallons

Calculated time to circulate RA slug around the end of the tubing and screen liner strings:

= 797.2 gal / 50 gpm

= 15.9 minutes

Note: Actual time surveys were run = 20 and 21 minutes

4.0 BOTTOM HOLE PRESSURE FALLOFF

Purpose Of Test: Required annual Reservoir Evaluation Test for year **1995.** Calculate the following reservoir characteristics: permeability, skin damage, pressure drop due to skin and flow efficiency.

4.1 FALLOFF TEST SUMMARY OF RESULTS

Method Of Interpretation: The following analysis was performed by utilizing both Semi-Log and Log-Log analysis. **A)** The Semi-Log curve was generated by plotting the standard Horner plot, **Pressure vs** $[(t_p+\Delta t)/\ \Delta t]$, using an injection time (t_p) of 96 hours. The semi-log straight line was calculated by linear regression through the infinite acting flow period of the curve. The slope **m**, P_{1hr}, and **P*** values were obtained from this curve and utilized for permeability and skin calculations. **B)** The Log-Log curves were generated by plotting **ΔP** and **Pressure derivative** vs the Agarwal Equivalent time function, $[t_p\ \Delta t/(t_p+\Delta t)]$. The Log-Log curves were simultaneously positioned over Gringarten type curves until a solution match was obtained. Permeability and skin values were calculated from this match and then compared with those obtained from the Semi-Log analysis.

A. Semi-Log (Horner) The straight line area of the semi-log curve was identified by first using the 1-1/2 log cycle rule to estimate the end of wellbore storage effects. Secondly, the time of the plat portion from the Pressure Derivative curve was used in determining the area of the semi-log curve in which the straight line was drawn. The semi-log straight line yielded a slope value of **4.876 psi/cycle** and a P_{1hr} of **1475.9** psi. The pressure difference between P_{1hr} and the injection pressure, P_{inj} of **1843.2** psi followed with the calculated slope would give indications of positive skin damage and high permeability.

B. Non-Linear Regression Using a homogeneous storage-skin-boundaries model, a non-linear regression routine was accessed to estimate the permeability, skin effect, and storage capacity that best fit the pressure data. The results of these computations are shown in the accompanying tables and are in excellent agreement with the results of the Horner plot.

C. Log-Log (Pressure and Pressure Derivative Plots) Figure 4 is a type-curve plot of the measured pressure data. Because of the high skin-effect and the high permeability of the formation, the pressure data lie above the existing type curves; consequently, type-curve analysis was not possible. However, the derivative plot shows that the middle time flow regime had been reached.

Conclusions This particular well was diagnosed to be injecting into a homogeneous reservoir with a calculated permeability of **737.5 (md)** and skin damage of **79.8** utilizing an h_{net} value of **165** feet. The flow efficiency of **19%** suggests that the near wellbore properties have a large affect on the injection volume limitations. The total pressure drop is primarily due to formation damage within a small radius from the well.

The following Table is provided to give comparative results with the previous tests and calculations. The primary variables affecting the calculated results are included.

Table 4.1

Summary of Results

Date MM/YY	Rate gpm	h_{net} ft	μ_w cp	slope psi/cycle	kh/μ	kh md-ft	k md	Skin
10/95	150	165	0.7100	4.876	171387	121685	738	+80
01/95	144	165	0.7100	3.848	208622	148122	897	+99
10/93	133	165	0.7017	4.558	163594	114789	696	+83

The calculated results indicate a difference in transmissibility, (kh/μ) of **17.8%** coupled with a **19.2%** difference in skin values between January and October 1995. In addition, the results calculated from non-linear regression analysis compare favorably to those calculated from the semi-log straight line analysis thus supporting the integrity of the calculated results. This compares to the petition transmissivity of 313,700 md-ft/cp.

The start time of the infinite acting flow period exceeded the time to exit the waste front, therefore the viscosity of the original reservoir fluid was used for the final analysis. The program used for final analysis and well simulation was "FAST", marketed by Fekete.

The formation pressures predicted by the model assume no formation damage effects or other near-bore well conditions. The measured flowing pressures corrected for skin effects and maximum predicted operational pressures are presented in the Table below:

Table 4.2

Formation Pressures

Well Name	Flowing Formation Pressures, psia	Skin Pressure Loss, psia	Revised Formation Pressure, psia	Maximum Modeled Pressure, psia
WDW-32 (Well No. 3)	1950.27 @ 3440'	338	1612	1641

The measured flowing pressure is below the maximum modeled operational pressure by more than 29 psi for WDW-32. A graph of the modeled pressures for WDW-32 is included as Appendix E. The graph shows the yearly predicted operations formation pressure (1991 through the end of 2000) using maximum modeled injection rates (250 gpm in each well). All predicted operational pressures correspond to a depth of 3440 feet below ground level and an original estimated formation pressure for the upper Miocene injection interval of 1555 psia.

The measured static formation pressures from the well tests, corrected to a depth of 3440 feet below ground level, show a formation pressure increase of 21 psi. This illustrates that injection operations at the plant have had limited impact on formation pressures and should continue to have limited impact on formation pressures in the future.

Table 4.3

Static Formation Pressure

Well	Static Formation Pressure, psia @ 3440'	Formation Pressure Increase, psia
WDW-32 (Well No. 3)	1576	+21

Table 4.4
Well Information

Well Type - INJECTION
Perforations: 3315' - 3553' (Gravel Pack Screen)

Gauge Depth 3192 feet

[Input Parameters]

Reservoir Pressure	psia	P	1469
Reservoir Temperature	Deg F	T	98
Final Static Pressure	psia	P_{si}	1469
Final Injection Pressure	psia	Pinj	1843.2
Water Flow Rate	gal/min	qw	150
Sand Thickness	feet	h_{net}	165
Wellbore Radius	feet	r_w	0.5830
Formation Porosity	%	ϕ	33.0
Extrapolated Pressure	psia	P*	1466.2
Extrapolated Press @ 1hr	psia	P_{1hr}	1475.9
Semi-Log Slope	psi/cycle	M	4.876
Production Time	hrs	t_p	96
Shut-in Time	hrs	t_{si}	34

[Fluid Properties]

Fluid Viscosity	cp	μw	7.1000E-01
Formation Volume Factor	RB/STB	βw	1.0
Fluid Compressibility	1/psi	Cw	3.0E-06
Total Compressibility	1/psi	Ct	6.0E-06

Table 4.5
Calculated Results

[Semi-Log Analysis - Horner Method]

Transmissibility	md-ft/cp	kh/u	171,387
Flow Capacity	md-ft	kh	121,685
Permeability	md	k	737.5
Skin Damage	total	S	+79.8
Pressure Drop due to Skin	psi	dP	+338
Flow Efficiency	%	FE	+19
Drainage Radius	feet	r_d	1179

FIGURE 2

HORNER
PRESSURE FALLOFF PLOT

HOECHST CELANESE
WDW-32 NO.3

PRESSURE FALL-OFF TEST
OCTOBER 24-26, 1995

$[k_1/u]_t = 1038.71$ $k_1 = 737.49$ md $s = 79.8$ $p^* = 1466.2$

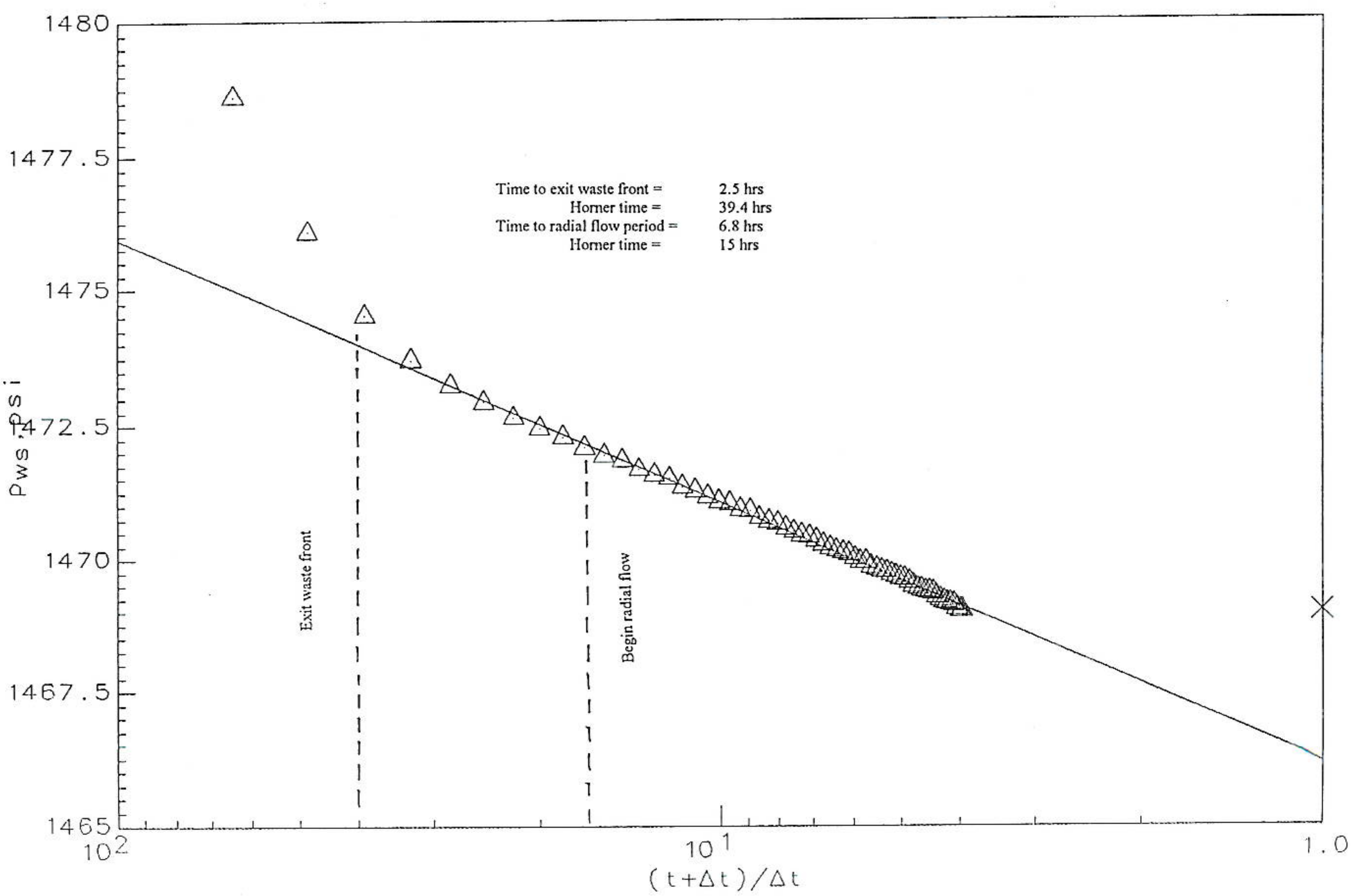


FIGURE 3

HORNER
PRESSURE FALLOFF PLOT

HOECHST CELANESE
WDW-32 NO.3

PRESSURE FALL-OFF TEST
OCTOBER 24-26, 1995

$[k_1/u]_t$=1038.71 k_1=737.49 md s=79.8 p*=1466.2

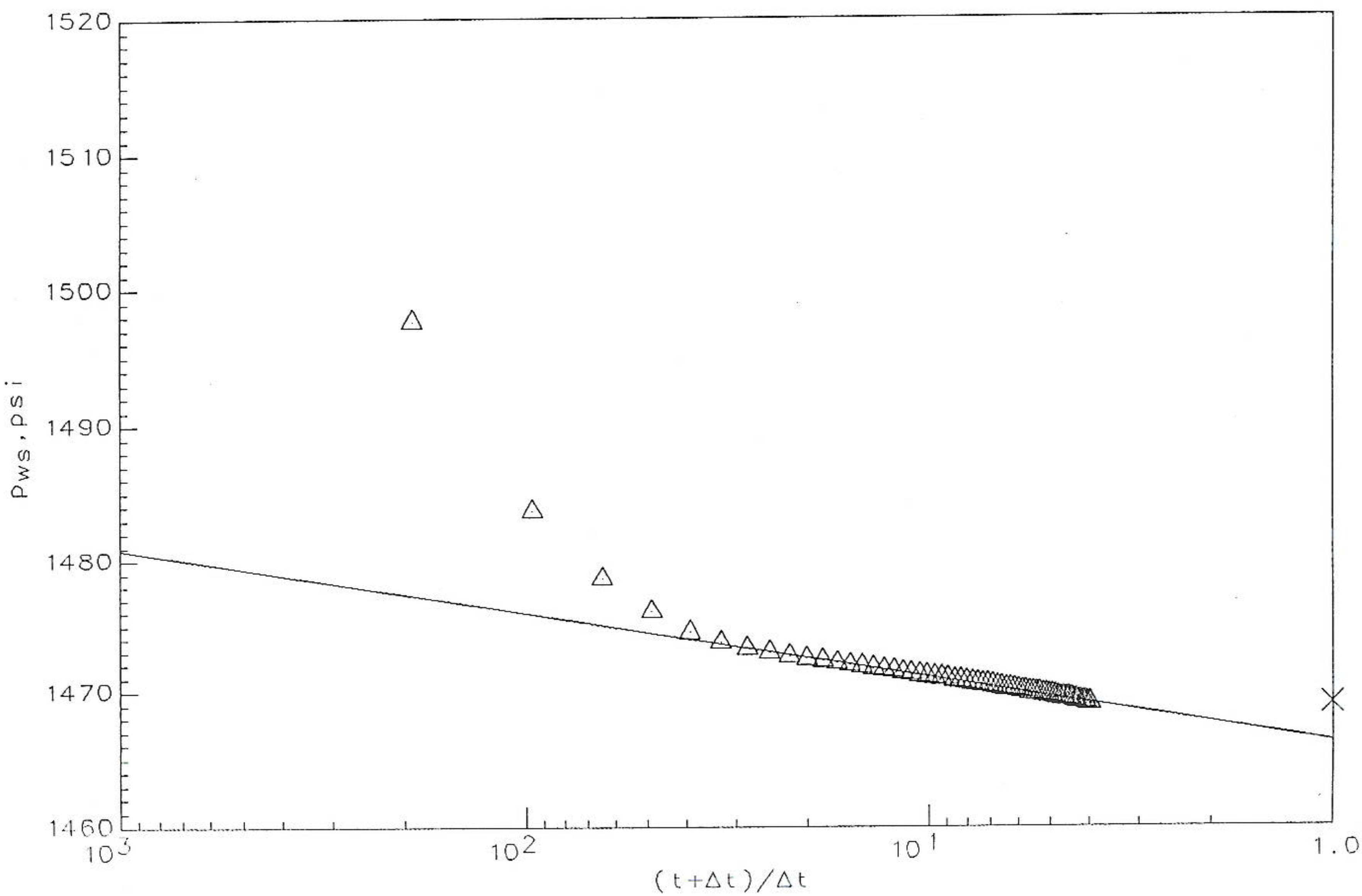


FIGURE 4

STORAGE - SKIN - BOUNDARIES

HOECHST CELANESE
WDW-32 NO.3
PRESSURE FALL-OFF TEST
OCTOBER 24-26, 1995

Ave Error=0.8 psi
Synthetic p_i= 1466.2 psi

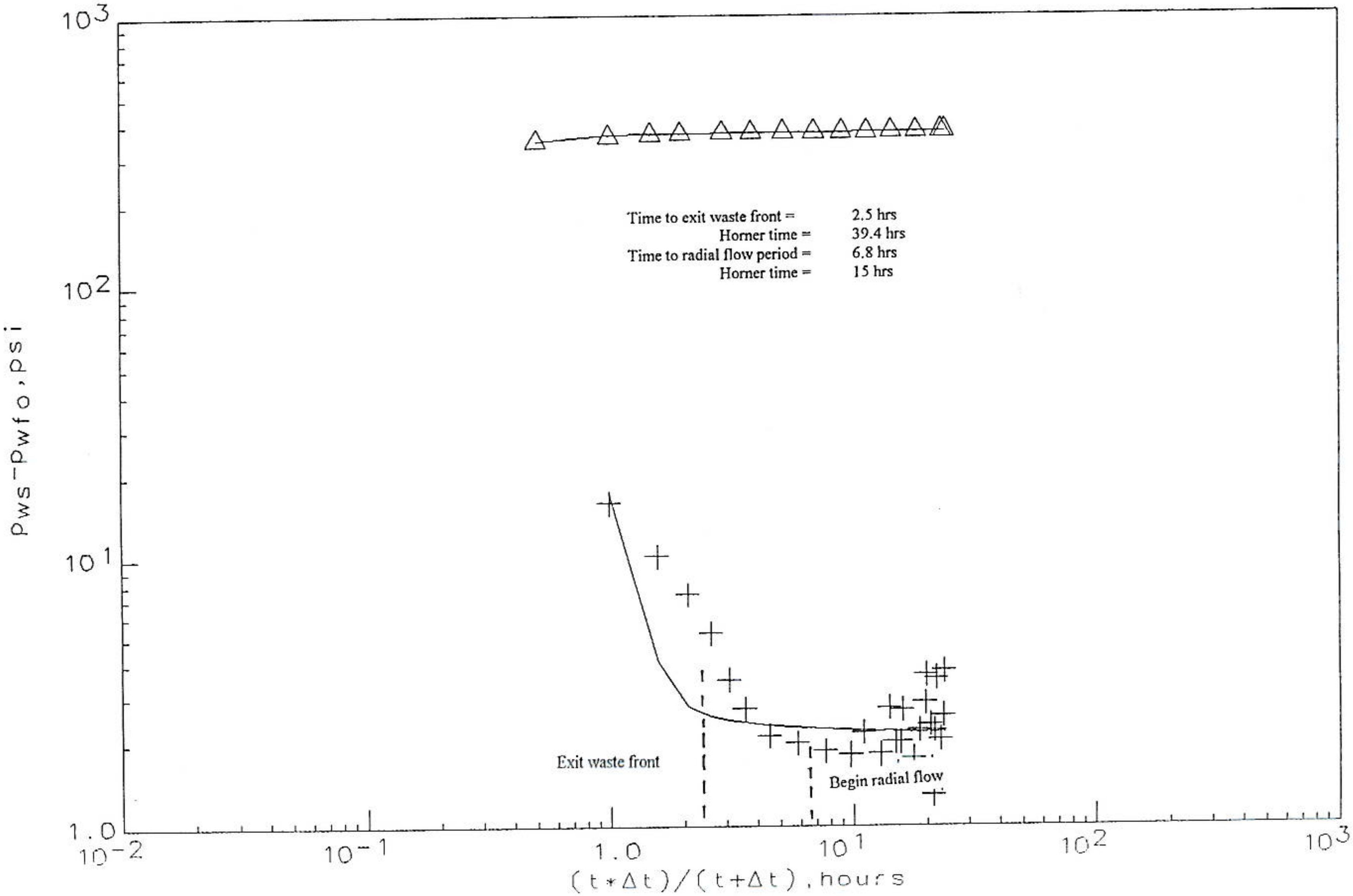


FIGURE 5

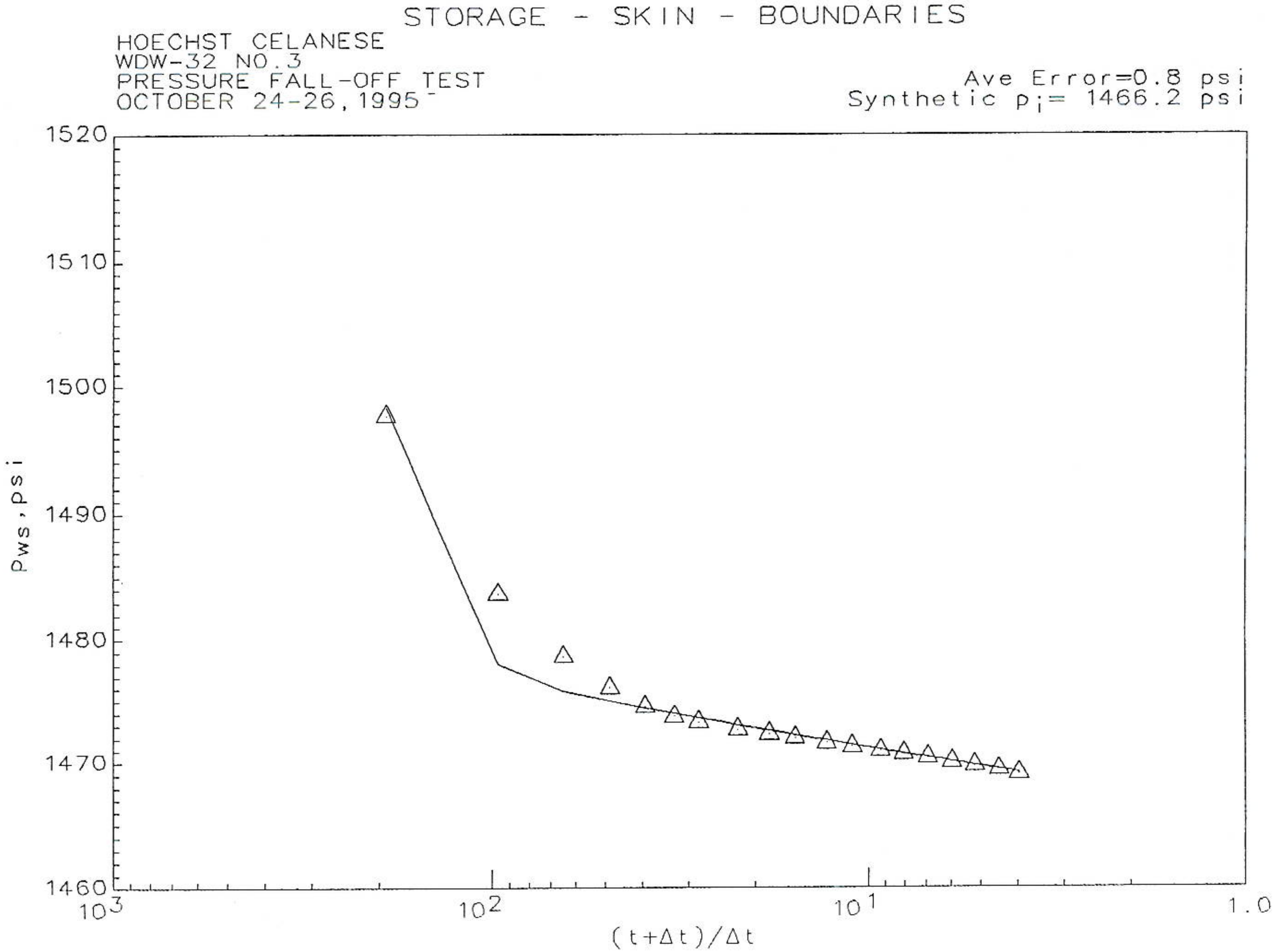

STORAGE - SKIN - BOUNDARIES
HOECHST CELANESE
WDW-32 NO.3
PRESSURE FALL-OFF TEST
OCTOBER 24-26, 1995
Ave Error=0.8 psi
Synthetic pi= 1466.2 psi
1520
1510
1500
1490
1480
1470
1460
Pws, psi
10^3
10^2
10^1
1.0
(t+Δt)/Δt

FIGURE 6

STORAGE AND SKIN TYPECURVE (Bourdet et al)

PRESSURE FALLOFF PLOT

HOECHST CELANESE
WDW-32 NO.3
$[k_1/u]_t$=744.09 k_1=528.30 C_D=1900 s= -

PRESSURE FALL-OFF TEST
OCTOBER 24-26, 1995

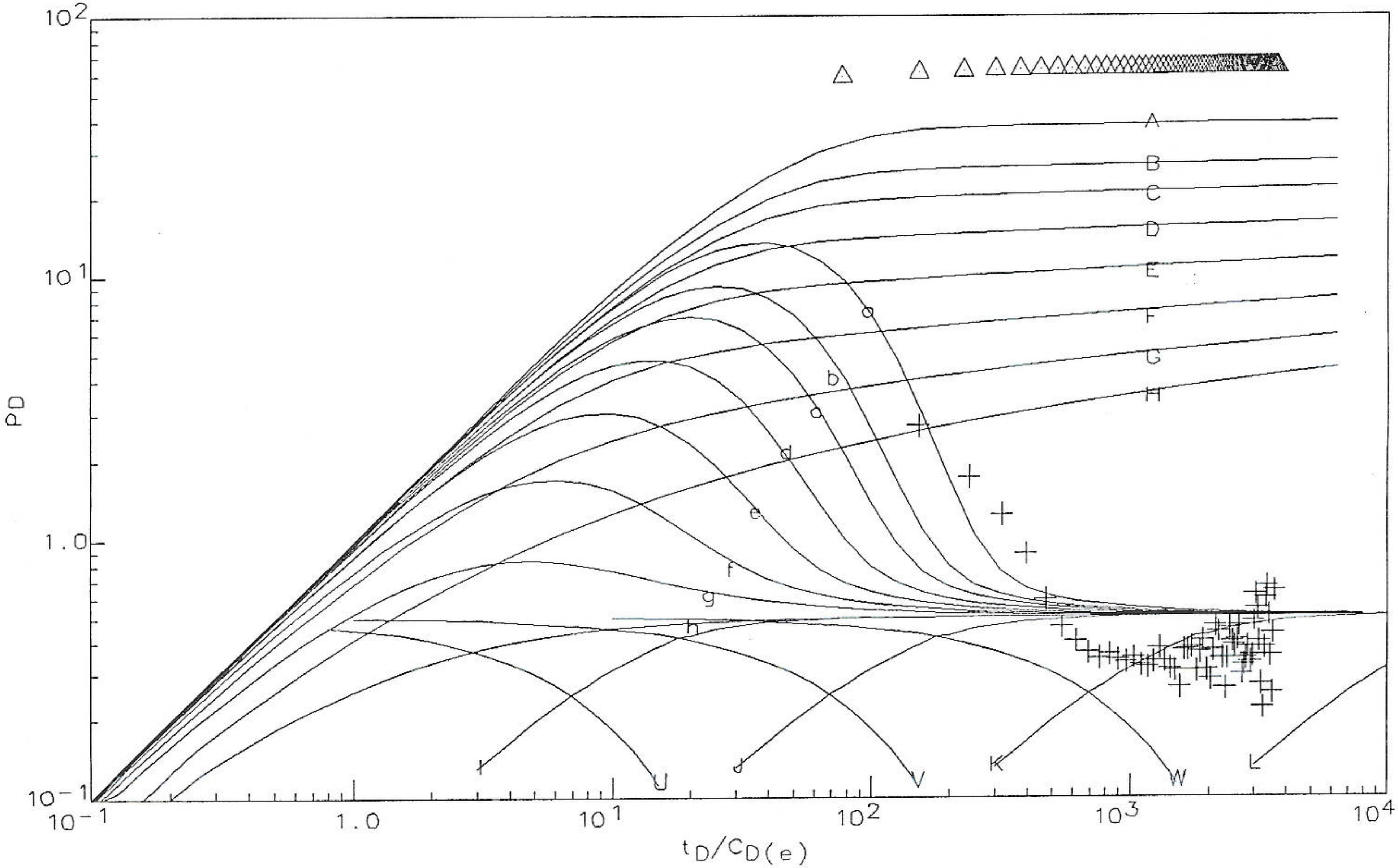


Table 4.6
FALLOFF TEST

Radial Flow Analysis

(Horner Time)

HOECHST CELANESE
WDW-32 (WELL NO. 3)

PRESSURE FALL-OFF TEST
OCTOBER 24-26, 1995

Reservoir Parameters

Net Pay	h =	165.00	ft	
Total Porosity	phit =	33.00	%	
Water Saturation	Sw =	0.00	%	
Wellbore Radius	r_w =	0.58	ft	
Formation Temperature	T =	98.00	deg F	
Formation Compressibility	c_f =	3.000×10^{-06}	psi^{-1}	
Total Compressibility	c_t =	6.000×10^{-06}	psi^{-1}	<DEF>

Table 4.6 (Continued)

Radial Flow Analysis

(Horner Time)

HOECHST CELANESE
WDW-32 (WELL NO. 3)

PRESSURE FALL-OFF TEST
OCTOBER 24-26, 1995

Zone 1

Pressures

Initial Pressure	pi =	1469.0	psi
Extrapolated Pressure	p* =	1466.2	psi
Average Reservoir Pressure	pR =	-	psi
Final Flowing Pressure	pwfo =	1843.2	psi

Straight Line Results

Total Sandface Rate	QTBT =	5143.00	bbl/d
Semilog Slope	msl =	4.9	psi/cycle
Transmissivity (Total)	kh/mu =	171387.54	md.ft/cp
Mobility (Total)	k/mu =	1038.712	md/cp
Flow Capacity (Oil)	kh =	121685.15	md.ft
Permeability (Oil)	k =	737.49	md
Skin Effect (Total)	s =	79.813	
Pressure Drop Due To Skin	delps =	338.2	psi
Flow Efficiency	FE =	0.19	
Damage Ratio	DR =	5.18	
Radius Of Investigation	r(inv) =	-	ft
@ Time Of Investigation	t(inv) =	-	hr

Table 4.6 (Continued)

Radial Flow Analysis

(Horner Time)

HOECHST CELANESE
WDW-32 (WELL NO. 3)

PRESSURE FALL-OFF TEST
OCTOBER 24-26, 1995

Zone 1

Extended Rates

3 - Month Constant Rate	=	-	bbl/d
6 - Month Constant Rate	=	-	bbl/d

Stabilized Rate

Time To Stabilize	ts =	5.038	hr
Stabilized Rate @ Current Skin	qs =	-5811.16	bbl/d
Stabilized Rate @ Skin Of 0	qs =	-65862.12	bbl/d
Stabilized Rate @ Skin Of -4	qs =	-136615.27	bbl/d

Table 4.7

Model Parameters

Storage - Skin - Boundaries Model

HOECHST CELANESE
WDW-32 (WELL NO. 3)

PRESSURE FALL-OFF TEST
OCTOBER 24-26, 1995

Synthetic Initial Pressure	=	1466.2	psi
Formation Parameters			
Transmissivity (Total)	kh/mu =	168683.15	md.ft/cp
Mobility (Total)	k/mu =	1022.322	md/cp
Flow Capacity	kh =	119765.03	md.ft
Permeability	k =	725.85	md
Skin	s =	78.434	
Wellbore Storage Constant (dim.)	CD =	810.75	
Inter Porosity Coeff	Lambda =	-	
Storativity Ratio	Omega =	-	
N.B. Origin At Lower Left Corner			
Reservoir Length	(xe) =	100000	ft
Reservoir Width	(ye) =	100000	ft
Active Well At	xw =	50000	ft
Active Well At	yw =	50000	ft

Table 4.8
SYNTHESIZER

Storage - Skin - Boundaries Model

HOECHST CELANESE
WDW-32 (WELL NO. 3)

PRESSURE FALL-OFF TEST
OCTOBER 24-26, 1995

Injection Pressure				
Final Injection Rate	qo =	-5143.00	bbl/d	
Final Flowing Pressure	Pwfo =	1843.2	psi	
Fluid Properties				
Reference Pressure	pRef =	500.0	psi	
Solution Gas Oil Ratio	Rso =	1.0	scf/bbl	
Reservoir Parameters				
Net Pay	h =	165.00	ft	
Total porosity	phit =	33.00	%	
Water Saturation	Sw =	0.00	%	
Wellbore Radius	rw =	0.58	ft	
Formation Temperature	T =	98.00	deg F	
Formation Compressibility	cf =	$3.000\times10^{-06}psi^{-1}$		
Total Compressibility	ct =	$6.000\times10^{-06}psi^{-1}$		<DEF>

Table 4.8 (Continued)
SYNTHESIZER

Storage - Skin - Boundaries Model

HOECHST CELANESE
WDW-32 (WELL NO. 3)

PRESSURE FALL-OFF TEST
OCTOBER 24-26, 1995

Synthesis Results

Average Error	=	0.8	psi
Initial Pressure	pi =	1469.0	psi
Average Reservoir Pressure	pR =	1466.2	psi
Pressure Drop Due To Skin	delps =	-	psi
Flow Efficiency	FE =	1.90	
Damage ratio	DR =	0.53	

Extended Rates

3 - Month Constant Rate	=	-5052.60	bbl/d
6 - Month Constant rate	=	-5032.69	bbl/d
1 - Year Constant Rate	=	-5008.53	bbl/d
1 - Year Constant Rate @ Skin Of 0	=	-39209.68	bbl/d
1 - Year Constant Rate @ Skin Of -4	=	-60160.14	bbl/d

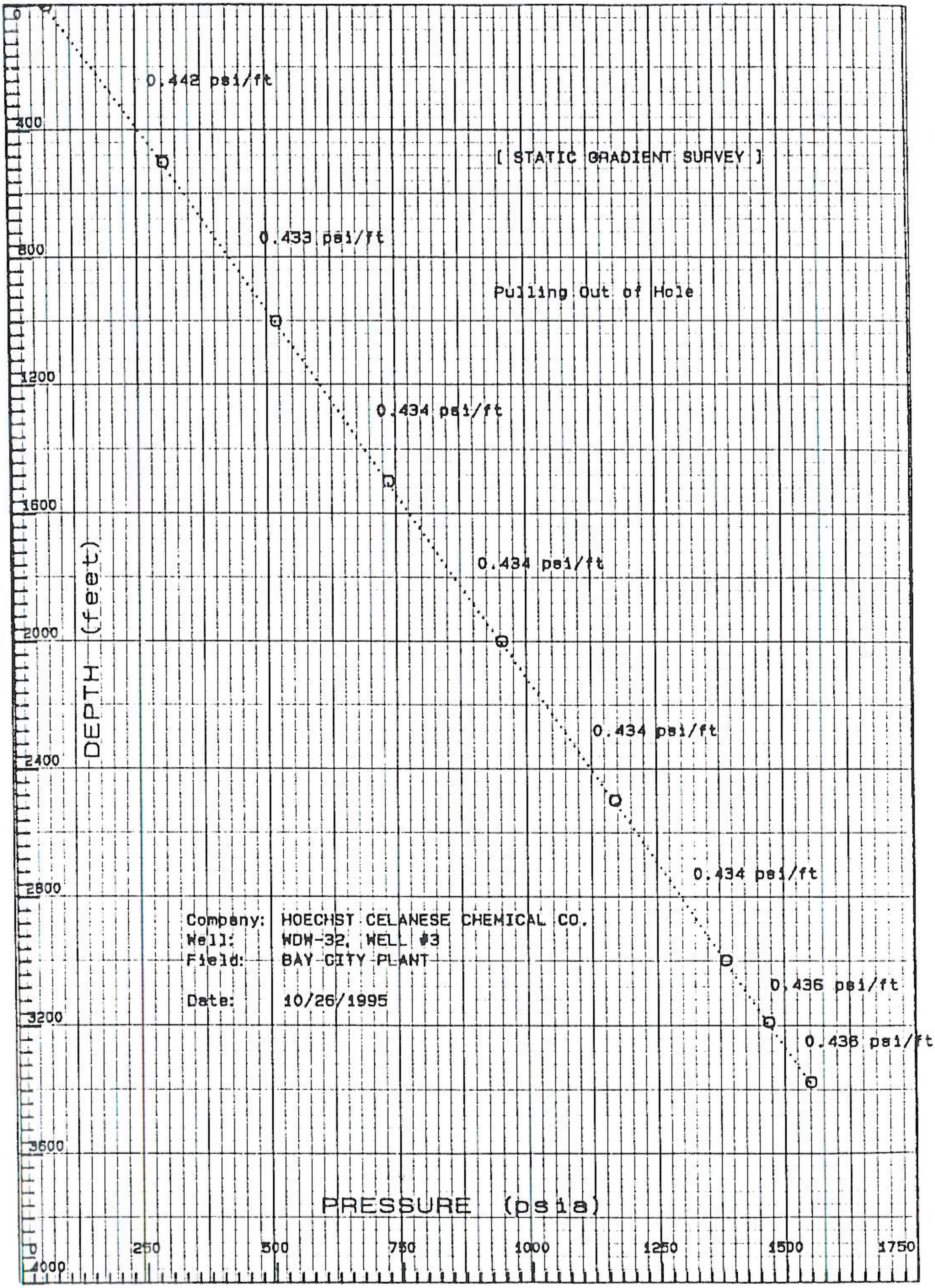
4.2 STATIC GRADIENT SURVEY

A static gradient survey was conducted while pulling out of the hole immediately following the bottom hole pressure falloff test. Stops were made at 3000', 2500', 1500', 1000', 500' and surface. Data collected during the static gradient survey is included in Appendix G and presented graphically in Figure 7. Data collected at each stop were as follows:

Table 4.9
Static Gradient Survey Results

Depth (ft)	Pressure (psia)	PSI/ft
0	78.16	
500	299.23	0.442
1000	515.91	0.433
1500	732.94	0.434
2000	950.13	0.434
2500	1167.31	0.434
3000	1384.43	0.434
3192	1468.15	0.436
3440*	1576.28	0.436

* Pressure extrapolated to mid-point perforations.



[STATIC GRADIENT SURVEY]
Pulling Out of Hole
0.442 psi/ft
0.433 psi/ft
0.434 psi/ft
0.434 psi/ft
0.434 psi/ft
0.434 psi/ft
0.436 psi/ft
0.438 psi/ft
Company: HOECHST CELANESE CHEMICAL CO.
Well: WDW-32, WELL #3
Field: BAY CITY PLANT
Date: 10/26/1995
DEPTH (feet)
0
400
800
1200
1600
2000
2400
2800
3200
3600
4000
PRESSURE (psia)
0
250
500
750
1000
1250
1500
1750